CALIFORNIA
ENERGY
COMMISSION

Guidance to the California Climate Action Registry: General Reporting Protocol

DRAFT CONSULTANT REPORT

MARCH 2002
P500-02-005D

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

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Executive Summary

California Senate Bill 527, which was signed into law in October 2001, establishes the California Climate Action Registry. The Registry will allow organizations to voluntarily report baseline and annual greenhouse gas (GHG) emissions results. Organizations that make use of this opportunity and submit results certified in accordance with the provisions of the bill receive the state's commitment to use its best efforts to ensure that the organizations receive appropriate consideration under any future international, federal, or state regulatory regime related to GHG emissions.

Senate Bill 527 directs the California Energy Commission to provide guidance to the Registry on procedures and protocols for reporting GHG emissions. Provisions of the bill are specific in many respects about how Registry reporting should be done, stating for example, that registered emissions be for an entity in its entirety, rather than only for specific projects, that emissions baselines against which organizations track trends in emissions be adjusted for changes in the structure of the organization, and that emissions results submitted to the Registry be certified. Nevertheless, SB 527 is silent on how many of the details of Registry reporting should occur. This purpose of this report is to provide guidance on these reporting details.

The body of this report is organized into four chapters that reflect the steps Registry participants will take in reporting their emissions:

- Reporting Boundaries,
- Emissions Estimation,
- Emissions Reporting, and
- Certification.

Each of the chapters is structured similarly. They begin with a description of the guidance on an issue and are followed by a discussion. At the beginning of each discussion, the relevant language of SB 527 that address specific issues is presented.

As GHG emissions inventorying is still an emerging area, standards for conducting inventories have not yet been established. Therefore, a variety of approaches are possible on issues involved in reporting GHG emissions. Some of the key questions, and the approaches recommended by this report are as follows:

1. **How should organizations account for emissions from sources they only partially own or control?** Consistent with the language of SB 527, the guidance recommends that all of the emissions be reported by the organization that has management control of the source—unless the owners decide to report on a pro rata basis (e.g., by ownership share). To allow the state to provide greater protection for reported emissions results, the guidance further recommends that the Registry allow participants to report by both management control and equity share, should the participants so choose.

2. **Should the Registry require that participants only use a standard set of emission factors in calculating their emissions?** The guidance recommends a set of emission factors that are consistent with the factors used in conducting the California statewide inventory of GHG emissions. To provide greater flexibility in reporting, mandatory use of these factors is not recommended, however. Alternative, standard sets of emission factors which may be used by Registry participants are listed, and participants are encouraged to use fuel or source-specific factors that are more accurate than the Registry factors for their particular emission sources.

3. **How should de minimis reporting levels be set?** De minimis emissions are those that when summed across all applicable sources of a particular entity fall below a certain threshold. The guidance recommends that this threshold be set as the lesser of a percentage and an absolute emissions level. The recommended threshold for de minimis emissions is five percent of the participant's total emissions or 10,000 metric tons (of carbon dioxide equivalent emissions) for a facility, whichever is less. Defining de minimis in this way ensures that both large and small participants will report substantially all of their emissions, and that large sources of emissions (in absolute terms) are not neglected merely because they are from very large emitters. To provide maximum flexibility to reporters, the definition of emissions sources and greenhouse gases that may fall within the de minimis category is left to the discretion of the Registry participants.

4. **What level of reporting detail should the Registry require?** Consistent with the intent of the Registry to maintain high quality emissions results, and the need for the both the emissions results and methodologies to be certified, the guidance recommends that for each facility of a participant, activity data (e.g., fuel consumption) and emission factors be submitted to the Registry along with the baseline and annual emissions results. It also recommends that a listing of the emissions source categories included in the inventory, a description of the emissions estimation methodologies, and a discussion of assumptions be part of the reporting.

5. **What options should the Registry allow for certification?** The guidance recommends three options for certification, consistent with size and level of complexity of the participant. In all cases, the certification process will include a review of both the reporting process and underlying data. The options differ, however in the amount of effort required and the need for site visits to confirm the results. The intent of having different options is to balance the cost of certification, particularly for participants with relatively small emissions, with the need for the Registry to have quality data that the state can stand behind.

The answers to these key questions, and more generally the material contained in this report, draw on a wide range of published sources, both foreign and domestic. Comments from a number of parties including the California Climate Action Registry (Registry), the California Air Resources Board (CARB), the U.S. Environmental

Protection Agency (EPA), and a self-selected Work Group were considered by the California Energy Commission staff, and the Commission’s contractor, Arthur D. Little, Inc., in preparing this report.

1.0 Introduction

In October 2001, Governor Gray Davis signed Senate Bill 527 (SB 527) establishing the California Climate Action Registry. SB 527 recognizes the interest of the state in encouraging voluntary actions to achieve economically beneficial greenhouse gas (GHG) emission reductions, and the possibility that mandatory GHG emissions reductions may be imposed on California sources in the future. It acknowledges the state's responsibility to use its best efforts to ensure that organizations that voluntarily inventory their emissions receive appropriate consideration for changes in these emissions prior to the implementation of any mandatory programs.

The California Climate Action Registry is established by SB 527 to allow organizations to voluntarily report baseline and annual GHG emissions results. Organizations that make use of this opportunity and submit results certified in accordance with the provisions of the bill receive the state's commitment to use its best efforts to ensure that the organizations receive appropriate consideration under any future international, federal, or state regulatory regime related to GHG emissions.

Senate Bill 527 directs the California Energy Commission to provide guidance to the Registry on procedures and protocols for reporting GHG emissions. Additionally, the Commission is to provide guidance for a certification protocol and for a process to qualify providers of technical assistance and certification services related to the Registry. The Registry will be developing industry-specific reporting protocols.

Many provisions of SB 527 are specific as to how Registry reporting is to be conducted. As provided by the bill, GHG emissions reporting to the Registry will:

- Be based on entity-wide annual reporting, not reporting for individual projects
- Apply to emissions in California and allow for reporting United States emissions
- Include emissions of carbon dioxide during the first three years of participation, and emissions of all of the greenhouse gases covered under the Kyoto Protocol in subsequent years
- Allow baselines to be set as far back as 1990, if sufficient data are available
- Require baseline adjustments for certain changes in the structure of an organization
- Be certified by an independent party

While specific in many respects, SB 527 leaves many of the details of Registry reporting to be filled in by the reporting protocol. This purpose of this report is to provide guidance on these reporting details. In final form, this guidance will be provided to Registry, which may adopt for use in it's general reporting protocol.

The approaches described in this guidance draw on a wide range of sources, both foreign and domestic. The experience and recommendations of existing GHG reporting programs has been drawn heavily upon in formulating the recommendations contained in this report, in particular the Greenhouse Gas Protocol (WRI, 2001), a multi-stakeholder effort to develop a standardized approach to the voluntary reporting of GHG emissions.

Comments from a number of parties including the California Climate Action Registry (Registry), the California Air Resources Board (CARB), the U.S. Environmental Protection Agency (EPA), and a self-selected Work Group were considered by the California Energy Commission staff, and the Commission's contractor, Arthur D. Little, Inc., in preparing this report. The Work Group, which includes industry, environmental groups, government agencies and the general public, has been providing comments on "straw proposals" for portions of a general protocol. The material contained in this guidance does not reflect fully the views of any single party, however, nor does it necessarily reflect a consensus view on particular issues.

The chapters in this report are presented in the same order as the steps Registry participants will take in reporting their emissions. The report is divided into four main chapters:

- Reporting Boundaries,
- Emissions Estimation,
- Emissions Reporting, and
- Certification.

Upon joining the Registry, participants will have to determine exactly what the boundaries of their emissions reporting will be before they begin to estimate their emissions. Once they have made their boundary determinations, they will estimate their emissions and report them to the Registry. The final step in the process is to have their reported results certified. Options for certification are described in this report. The certification section of this report is not a protocol for certification, however. The Commission will be providing recommendations for a certification protocol as a separate document.

Each chapter of this report is structured similarly. It begins with a description of the guidance on an issue and is followed by a discussion. At the beginning of each discussion, the relevant language of SB 527 that address specific reporting issues is presented. This is followed by a discussion of the issue and the rationale for the guidance that is presented.

The main chapters of this report are followed by a list of references and several appendices. Appendix A presents comparison tables of U.S., foreign, and California GHG and air pollution programs that have had to decide questions similar to those facing Registry participants. Appendix B is a review of GHG emission estimation methodologies used in the statewide California inventory—specifically for non-combustion emissions sources. It is included because SB 527 requires that to the extent practicable, the methods used for Registry reporting be consistent with those used in the statewide inventory. Appendix C provides examples of estimation methods that may be incorporated into future industry-specific protocols.

2.0 Reporting Boundaries

The first step in conducting an emissions inventory is to establish its boundaries. This means determining which sources of emissions are to be included based on the participant's organizational structure, its operations, and the locations of its emissions sources. For many Registry participants, particularly firms that are wholly-owned entities operating entirely within the State of California, establishing reporting boundaries will be straightforward. For participants whose operations consist of jointly-owned entities and those with operations outside of California, the process will be more involved. This Chapter gives guidance to participants on how to set the boundaries of their inventory for reporting to the Registry.

Participants must identify which of their emissions will be reported to the Registry. First, they must define their reporting entity by establishing its **organizational boundaries**, including how to treat partially owned or operated assets. Next, they must determine their **operational boundaries**—those activities that should be included in their emissions inventory. Operational boundaries are determined by the nature of the operations that are required to be reported and by whether the magnitude of the emissions are large enough include them in the inventory. Finally, participants must determine the **geographic boundaries** that apply to their emissions whether they be reporting emissions for California only or for both California and the entire United States.

2.1 Organizational Boundaries

The basic unit of participation in the Registry is an entity in its entirety, such as a corporation or other legally constituted body, any city or county, and each state government agency. Reporting for individual facilities or projects is not allowed unless they are included as part of an entity's total emissions reporting. Any entity that conducts business activities in the State of California may report to the Registry.

The determination of organizational boundaries for reporting to the Registry is straightforward for organizations that wholly own and fully control all of their GHG emissions sources. These organizations simply report all of their material emissions to the Registry.

2.1.1 Partial Ownership and Reporting by Management Control

For facilities that are owned or controlled by more than one organization, determining the organizational boundary is more complicated. The organizational boundary required for Registry reporting is based on the management control of the facility, except as described below. The approach to management control reporting described here is based on that presented in the *Greenhouse Gas Protocol* (WRI, 2001).

Management control is defined as the ability of an entity to govern the operating policies of another entity or facility so as to obtain benefits from its activities. Typically, if an entity owns 50 percent or more of the voting interests, this implies control.

In practice, the exercise of dominant influence itself is enough to satisfy the definitions of control without requiring any formal power or ability through which it arises. Such dominant influence can be evidenced by:

- Controlling more than one half of the voting rights by virtue of an agreement with other investors;
- Governing the financial and operating policies of the other enterprise under a statute or an agreement;
- Appointing or removing the majority of the members of the board of directors; or,
- Casting the majority of votes at a meeting of the board of directors.

In the case of **joint control**, (as defined by International Accounting Standards), no individual party has management control because no individual party has dominant interest. Parties with 20 to 50 percent of the voting interests are considered to have significant influence, however. Consistent with approach recommended by the *Greenhouse Gas Protocol* (WRI, 2001), participants holding significant influence over a facility should include emissions by **equity share** based on their ownership interest in the facility. If the participant owns less than a 20 percent interest in the facility, the reporting of emissions by equity share is optional. The participant may choose simply not to report any emissions from the facility in this case.

Using management control as the basis for setting organizational boundaries, Registry participants should account for and report their GHG emissions according to the framework presented in Table 2.1.

Table 2.1 Reporting requirements under management control

Level of Control	*Percent of GHG Emissions to Report*
Wholly owned	100%
Not wholly owned but controlled	100%
Jointly controlled	By Equity Share*
Non-controlled	0%

* Reporting is optional for less than 20 percent equity share

2.1.2 Partial Ownership Issues

The issue of partial ownership may raise a number of questions among participants including:

Operating License Considerations

For some participants, such as those in the petroleum industry, it is common to have joint ventures with a single operator. In some cases, holding the operating license also means having management control. However, holding the operating license is not a sufficient criterion for being able to direct the operating policies of an entity or facility. Therefore the criteria listed above for dominant influence should be used to determine whether a participant has management control, not the fact that the participant holds the operating license.

Non-incorporated Operations

The definition of 'management control' applies to incorporated as well as to non-incorporated operations. (Incorporated means that the operation has been established as a legal business corporation). Thus, GHG emissions have to be reported from incorporated as well as from non-incorporated entities/facilities.

Subsidiaries

Subsidiaries that are corporations or other legally constituted bodies may participate in the Registry as separate participants. If the parent company of a subsidiary is a Registry participant, the parent company should report the emissions of the subsidiary in accordance with the management control scheme illustrated in Table 2.1. Since by definition, a subsidiary company is one in which a parent corporation owns more than 50 percent of the stock (and thus would typically have majority voting rights), the parent company would typically report all of the subsidiary's emissions. Corporations that report baselines and annual results as subsidiaries must clearly define the parent corporation to the Registry. The parent company itself need not participate in the Registry merely because one or more of its subsidiaries chooses to participate.

Holding Companies

Corporations that are made up of several other corporations would report to the Registry following the same management control approach described above for joint ventures and subsidiaries. If the parent corporation controls several subsidiaries, it would report the total emission from the subsidiaries, and at its option the emissions of each subsidiary separately.

2.1.3 Partial Ownership and Pro Rata Reporting

There is an exception to the rule of reporting by management control. In the case of joint ownership, the owners may decide to report emissions on a **pro rata basis**, rather than having the entity with management control report all of the emissions (if there is an entity with management control, and if it is a Registry participant). This does not mean that all of the owners of a jointly held operation must report to the Registry, but rather that the owners who choose to report to the Registry will have to collectively decide to report on a pro rata basis. (Owners who are not Registry participants would not be required to report to the Registry in any case.)

The pro rata basis for emissions reporting will most commonly be based on equity share of ownership as illustrated in Table 2.2. Other pro rata methods may be used, however. This could include, for example, emissions reporting based on share of production output, or some other method based on the contractual agreements of the owners. Regardless of the method selected for pro rata formulation, owners that are Registry participants should agree to the method. The pro rata method must ensure that all applicable emissions of the participants are reported and that there is no potential for the non-reporting or double counting of participant emissions. Furthermore, once established, the pro rata method of reporting must be continued in subsequent annual reports. Any modifications to a pro rata method that result in changes to emissions reported and changes a participant's baseline must be clearly identified by the participant and approved by the Registry.

Table 2.2 Reporting based on equity

Level of Ownership	***Percent of GHG Emissions to Report***
Wholly owned	100%
Partially owned, equal to or more than 20% ownership	By Equity Share
Partially owned, less than 20% ownership	0%

2.1.4 Optional Reporting

Registry participants must report their emissions either on a management control or pro rata (equity share) basis. They are encouraged to report both ways. For participants whose primary method of reporting is based on management control, equity share reporting would be optional. For those reporting on an equity share basis, reporting by management control would be optional.

The reason for allowing participants to report in both ways is to enable the state to provide more comprehensive protection to a participant's baseline and annual emissions results. Since potential future regulatory schemes are uncertain, unless emissions by equity share are included in the Registry, the Registry will be of less value to participants wishing to receive consideration under any such future regulatory schemes. Participants that report only by management control cannot expect the state to be able to provide baseline protection for any future regulatory program that is based on equity share reporting. Conversely, participants that report only on an equity share basis cannot expect the state to provide protection under a future program based on reporting by management control.

Participants considering optional reporting should understand that little additional effort is involved in reporting by both equity share and management control. As is illustrated in the following examples, the difference in reporting occurs only among those facilities that are under management control of the participant. Emissions from facilities that are under significant influence (e.g., 20-50 percent of ownership) are reported on an equity share basis either reporting framework. The difference between management control and equity share reporting amounts to whether participants report 100 percent of the emissions of from facilities they control, or whether they report on an equity share basis for these facilities.

2.1.5 Organizational Boundaries Examples

The following are organizational boundary examples that contrast reporting by management control with reporting by equity share. For these examples, the percent of voting interest and percent of ownership are equal. Consistent with the management control approach recommended by the Greenhouse Gas Protocol (WRI, 2001), firms with significant influence are shown to report by equity share in these examples.

Case 1: Trivial case – Company A wholly owns the facility. Company A reports 100% of the emissions for both cases.

Participant	Facility	Management Control Reporting Requirements	Equity Share Reporting Requirements
Company A	Wholly owned by Company A (100% voting interest/ownership)	100%	100%
Company B	No ownership by Company B (0% voting interest/ownership)	0%	0%

Case 2: Company A has 60% ownership of the facility, and has management control. Company B has 40% ownership of the facility, and is not in management control.

Participant	Facility	Management Control Reporting Requirements	Equity Share Reporting Requirements
Company A	Not wholly owned by Company A, but controlled – dominant influence. (60% voting interest/ownership)	100%	60%
Company B	Not wholly owned by Company B, not controlled –significant influence (40% voting interest/ownership)	40%	40%

Case 3: Company A has 50% ownership of the facility, and likewise, Company B has 50% ownership of the facility. The facility is considered to be jointly controlled by both companies.

Participant	Facility	Management Control Reporting Requirements	Equity Share Reporting Requirements
Company A	Not wholly owned by Company A, but jointly controlled – significant influence. (50% voting interest/ownership)	50%	50%
Company B	Not wholly owned by Company B, but jointly controlled –significant influence (50% voting interest/ownership)	50%	50%

Case 4: Company A has 55% ownership of the facility, Company B has 30% ownership of the facility, and Company C has 15% ownership. The facility is considered to be jointly owned by all three companies. All owners agree to report on a pro rata basis by equity share under management control. Under the provisions of the protocol, Company C elects to not report based on ownership below 20% of value of the facility.

Participant	Facility	Management Control Reporting Requirements	Alternative to Management Control Reporting Requirements (Pro Rata Basis)	Equity Share Reporting Requirements
Company A	Jointly owned by Company A – dominant influence. (55% voting interest/ownership)	100%	55%	55%
Company B	Jointly owned by Company B –significant influence (30% voting interest/ownership)	30%	30%	30%
Company C	Jointly owned by Company C – no influence (15% voting interest/ ownership)	0%	0%	0%

Discussion

The following sections of the SB 527 are directly applicable to the Organizational Boundaries section of the protocol:

> SEC. 11. 42840(d)The basic unit of participation in the registry shall be an entity in its entirety such as a corporation or other legally constituted body, any city or county, and each state government agency. The registry shall not record emissions baselines and reductions for individual facilities or projects, except to the extent they are included in an entity's emissions reporting.
>
> (1) Corporations may report emissions baselines and annual emissions results from subsidiaries if the parent corporation is clearly defined.
>
> SEC. 11. 42840(b)(1)Participants shall report direct emissions and indirect emissions separately. Direct emissions are those emissions from applicable sources that are under management control of a participating entity. . .
>
> SEC. 11. 42840(b)(3) In cases of joint ownership, emissions are reported by the managing entity, unless the owners decide to report emissions on a pro rata basis.

SB 527 makes mention of reporting by management control in the context of defining direct emissions. The implication of this definition is that if a participant does not have management control in a facility, it does not have any direct emissions from that facility. In common usage (e.g., WRI, 2001) direct emissions are not limited to facilities where a single party has management control. Those where multiple parties have equity share, but none has management control, also have direct emissions.

SB 527 does not provide a definition of management control. Therefore, the definition of management control adopted for Registry reporting is based on the WRI/WBCSD formulation of management control reporting (WRI, 2001), in which the reporting entity reports:

- 100% of an entity's emissions for wholly owned entities,
- 100% of an entity's emissions for controlled but not wholly owned entities, and
- By equity share for jointly controlled entities in which the participant has 20 percent or more of the voting interests.

It should be recognized that under this scheme there is the possibility that significant emissions may not be reported. This would be the case if a Registry participant has less than a 20 percent voting interest in a large source of GHG emissions. In the case where all of the owners of the jointly controlled emitting entity were participants in the Registry, there is the possibility that none of the emissions would be counted if all of the parties had less than a 20 percent voting interest.

As indicated by SB 527, there is allowance for alternative reporting in the case of joint ownership. For joint ownership, reporting may be done on a pro rata basis at the discretion of the owners. To avoid inconsistencies among owners in situations where more than one of the owner is a participant in the Registry, the requirement that "owners decide" to report on a pro-rata basis is interpreted to mean that the owners collectively decide to report on this basis. For the purposes of the Registry, it is important that all of the participants, rather than all of the owners, agree on whether to report on a pro-rata basis

Existing reporting programs are split on whether reporting should be done by equity share or by management control. (See Appendix A.) The *Greenhouse Gas Protocol* (WRI, 2001) recommends that entities report both ways. The EPA's Climate Leader's program requires reporting by equity share, while the UK Emissions Trading Scheme is based on management control. Other programs, such as the Australia Greenhouse Challenge allow the participants to define how emissions are handled from jointly held assets. Allowing optional reporting by equity share will enable Registry participants to decide whether the possibility of receiving additional assurance in a any future regulatory program justifies the additional reporting effort in exceeding the requiring reporting as outlined in SB 527.

2.2 Operational Boundaries

After a participant has determined its organizational boundaries in terms of the applicable operations that it owns or controls, it must then define its **operational boundaries**. This section describes how to determine operational boundaries for Registry participation.

2.2.1 Direct and Indirect Emissions

Participants will report both direct emissions and specific indirect emissions.
Direct emissions are those emissions from applicable sources that are under control of an entity, including:

- Transportation emissions from vehicles owned or operated by the participant and used for moving raw materials, finished products, supplies, or people
- Emissions from onsite combustion for the production of heat, steam or electricity
- Process emissions, such as from the production of cement, adipic acid, and ammonia, as well as emission from agricultural processes
- Fugitive emissions such as methane leaks from pipeline systems and leaks of HFCs from air conditioning systems

Indirect GHG emissions are emissions that occur because of a participant's actions, but are produced by sources owned or controlled by another entity (WRI, 2001). Examples of indirect emissions include emissions resulting from electricity use, or business travel on commercial aircraft, or shipping products using a delivery service rather than the participant's own vehicles.

Registry reporting requires that emissions be reported only for the following three types of indirect emissions sources:

- Electricity imports
- Steam imports
- Heating and cooling obtained from district heating/cooling plants

In this context, "import" refers to the purchase by the participant of electricity, steam, heating, or cooling from outside of an entity's organizational boundary.

Registry participants are encouraged, but not required, to report other indirect GHG emissions. In addition to those noted above, these may include emissions from:

- Off site waste disposal
- Employee commuting
- Production and transport of purchased raw materials
- Product disposal

(Participants should note that in the future the Registry is planning to provide additional guidance on reporting on optional indirect emissions sources. This protocol provides guidance only on the estimation of emissions from indirect emissions sources that are required to be included.)

Indirect emissions are reported separately from direct emissions in the Registry. (The process for calculating indirect emissions is provided in Chapter 3, and guidance on reporting them is provided in Chapter 4.) Keeping indirect emissions separate from direct emissions serves two purposes. It allows questions of double counting to be avoided, since the Registry will easily be able to leave out the indirect emissions if it wishes to sum the direct emissions. It also allows the net emissions to be calculated for entities that both import and export energy.

2.2.2 Leased Facilities

If participants operate in leased facilities or use leased equipment, the associated emissions should be included within their inventory boundary if the participant directly purchases the electricity, fuel, or raw materials that result in GHG emissions. If the participant pays for electricity, fuel, or materials in operations that result in GHG emissions, it is presumed to have access to the data needed to calculate emissions and should include the relevant emissions in its inventory. For example, emissions from industrial operations in a leased building, emissions from fuel consumed by leased vehicles, emissions from leased equipment, and electricity metered and paid for by the participant in a leased office building would be reported by participants in the same manner as if the facilities, vehicles, equipment, or building were owned by the participant.

In the case of office or building space that is rented or leased, where the heating, electricity, cooling, or other utilities are paid for by the landlord and not separately metered for the participant, emissions associated with these items would not need to be reported by the participants. They would be reported by the landlord if the landlord participated in the Registry. However, the Registry is considering requiring participants to indicate on their reporting forms the approximate square footage of space for which they are not reporting indirect emissions because it is not separately metered.

2.2.3 Materiality

Participants are required to report any material emissions of greenhouse gases covered by Registry reporting. During the first three years after joining the Registry, this means the participant must report any material emissions of carbon dioxide (CO2). After their first three years of participation, participants must also report any material emissions of the other greenhouse gases included in the Registry:

- Methane (CH_4)
- Nitrous Oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur Hexafluoride (SF_6)

"Material" means any emission of greenhouse gas that is not de minimis in quantity when summed up across all applicable sources of the participating entity. In order to provide a consistent definition across all applicable emissions sources for large emitters as well as small, de minimis emissions for any reporter are defined as the lesser of:

- Emissions which in total are less 5 percent of the participant's total CO_2-equivalent emissions, or
- 10,000 tonnes of CO_2-equivalent emissions from a specific facility.

The percentage threshold would apply to California emissions for the purposes of California emissions reporting, and would apply to U.S. emissions for national reporting. The absolute threshold would apply equally for both forms of reporting.

By defining de minimis in this manner, all participants will be required to report at least 95 percent of their total emissions. Table 2.3 lists the 100-year global warming potentials (GWPs) to be used to express emissions on a CO_2-equivlaent basis. For gases other than carbon dioxide, the absolute de minimis level would be 10,000 tonnes divided by the GWP. (It should be noted that Working Group 1 of the Intergovernmental Panel on Climate Change has revised the GWPs shown in Table 2.3; while the report containing the new values has been accepted, it has not been approved in detail, and thus the earlier values are listed here.)

Table 2.3: Global Warming Potential (GWP) for Greenhouse Gases

Gas	100-Year GWP
CO_2	1
CH_4	21
N_2O	310
HFC-23	11,700
HFC-125	2,800

HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	5,700
C_2F_6	11,900
C_3F_8	8,600
C_4F_{10}	8,600
C_5F_{12}	8,900
C_6F_{14}	9,000
SF_6	23,900

Source: IPCC (1996)

The selection of source types that are considered to be de minimis is left up to the participant, and will vary from participant to participant. Fugitive GHG emissions can be expected to be de minimis for the vast majority of participants, for example, but will likely be material for participants involved in the transportation and distribution of natural gas. Participants will have to demonstrate that all of the emissions they consider de minimis constitute less than five percent of total emissions when summed across their entire entity.

Determining whether or not emissions are de minimis is the responsibility of the participant. The demonstration of de minimis may be made using the same procedures as for estimating emissions as described in Chapter 3, or using simplified procedures. For participants whose emissions come only from electricity and fuel consumption, for example, it would be sufficient to show that the emission factors for methane and nitrous oxide, when multiplied by their global warming potentials and added together are less than five percent of the corresponding emission factor for carbon dioxide. Assuming the participant deemed no other type of emissions to be de minimis, the total de minimis emissions would necessarily be less than 5 percent of the total.

While participants will have to demonstrate that the emissions they consider de minimis truly are de minimis when establishing their baseline or when beginning reporting, in reporting subsequent year emissions, they need only show that their operations have not changed enough to require a change in the sources they consider to be de minimis.

Discussion

The following sections of the SB 527 legislation are directly applicable to the operational boundaries definition of the protocol:

SEC. 11. 42840(b)

(1) Participants shall report direct emissions and indirect emissions separately. Direct emissions are those emissions from applicable sources that are under management control of a participating entity, including onsite combustion, fugitive noncombustion emissions, and vehicles owned and operated by the participant. Indirect emissions that are required to be reported by participants are those emissions embodied in net electricity and steam imports, including offsite steam generation and district heating and cooling. Participants are encouraged, but are not required, to report other indirect emissions based on guidance that is adopted by the registry.

SEC. 11. 42840(b)

(4) Participants shall not be required to report emissions of any greenhouse gas that is de minimis in quantity, when summed up across all applicable sources of the participating entity. The State Energy Resources Conservation and Development Commission shall recommend to the registry a definition of de minimis emissions that reasonably accounts for differences in the size, activities, and sources of direct and indirect baseline emissions of participants … .

SEC. 11. 42840(c)

(1) All participants shall report direct and indirect carbon dioxide (CO2) emissions that are material to their operations.

(2) The registry shall also encourage participants to monitor and report emissions of the following gases:(A) Hydrofluorocarbons (HFCs),(B) Methane (CH4),(C) Oxides of nitrogen [sic](N2O),(D) Perfluorocarbons (PFCs), (E) Sulfur hexafluoride (SF6).

(3) The report of information specified in paragraph (2) is optional for three years after a participant joins the registry. After participating in the registry for a total of three years, participants shall report emissions required by both paragraphs (1) and (2).

There are two key aspects to operational boundaries: (1) direct and indirect emissions and (2) the reporting of material or non de minimis emissions thresholds. The legislation clearly prescribes which direct and indirect emissions are to be included in the Registry reporting. The additional description of indirect emissions in this section comes from WRI/WBCSD (2001).

SB 527 is silent on the issue of indirect emissions that result from the consumption of electricity or other utilities at leased facilities when these utilities are not separately metered or paid for by the participant. The approach recommended for the protocol is based on the belief that in this situation there is no meaningful way for participants to track emissions. While generalized factors for electricity consumption or space heating based on the amount of floor space occupied may be available, these would provide only a very rough estimate of emissions, and their use would not reflect any actions taken by participants to reduce energy consumption over time.

SB 527 provides no definition of de minimis, leaving it to the protocol development process. Because the intent of SB 527 is that participants report essentially all of their applicable emissions, it is appropriate to define de minimis in terms of an entity's total emissions. By common definition, 95 percent or more constitutes complete.

The proposed de minimis approach is consistent with the range of accuracy in GHG reporting that is targeted by various governmental and private inventory programs. Participants in the Australia Greenhouse Challenge Program are expected to have reported emissions that are within 10 percent accuracy, and results of those that have been verified indicate that many types of reporters can achieve much better accuracy than this (Loreti et al, 2001). BP has a set an accuracy threshold of 5 percent for its total direct corporate emissions.

Setting de minimis thresholds for individual sources or even groups of sources suffers from a significant drawback. In the UK Emissions Trading Scheme, a reporting threshold of one percent of the total entity emissions (or 10,000 tonnes CO_2e, whichever is less) has been established (DEFRA, 2001). When a group of point sources of similar type within a single facility is less than the threshold, the group of sources need not be included in the reporting. While one percent may sound like a strict threshold, if an enterprise has multiple facilities (and defines its source groups narrowly) it may apply the threshold multiple times. The one percent threshold for a particular group of sources at one facility could translate into a much higher percentage when summed across the total reporting entity. To avoid this problem, the threshold for reporting to the Registry is based on the sum of all applicable sources compared to the total entity emissions.

The establishment of only absolute thresholds for reporting is commonly done for the reporting or regulation of conventional air pollutants. This approach is not appropriate for Registry reporting for two reasons. As previously noted, the goal of SB 527 is to report a complete picture of a participant's GHG emissions and thus the legislation requires reporting on an entity wide basis. Due to the large variability in the magnitude of emissions of potential participants, emissions that are a significant fraction of total emissions for smaller reporters will be insignificant fraction for larger ones. Setting only an absolute threshold will either result in larger participants having to expend significant effort to report emissions that are insignificant or smaller participants not having to report emissions that may account for a large fraction—or all—of their emissions. An absolute reporting threshold is thus also contrary to the Registry goal of having wide participation among organizations both large and small. Setting the de minimis threshold as the lesser of a percentage and an absolute level avoids this problem. Larger participants will not have to report relatively small sources, but will have to report emissions from sources that may be small relative to their total emissions but large in absolute terms.

It has been recommended that de minimis reporting levels be set so that they are no higher than the accuracy of emissions estimates for particular source types. This approach was rejected because it has the perverse effect of rewarding participants for using less accurate methods to quantify emissions—the less accurate the emissions estimation approach, the greater the de minimis level would be. The relative accuracy of GHG emissions estimates will vary. But as noted in Chapter 3, methods for estimating CO_2 emissions, the largest source of GHG emissions, are quite accurate in any case. In fact, the methods are more accurate than for conventional air pollutants, for which de minimis reporting levels are significantly less than the accuracy with which they are measured.

2.3 Geographic Boundaries

Registry participants are required to report emissions from all of their operations in California. Selective reporting of emissions only for specific facilities or projects within the state is not permitted.

Participants may, and are encouraged to, also register and report emissions nationwide. If a participant opts to report at the national level, the expanded reporting must meet all of the requirements established by the Registry for reporting California emissions. Those choosing to report at the national level will report both California and national emissions.

The requirement that participants report direct GHG emissions from mobile sources that they own or lease and operate raises the question of how emissions should be accounted for when sources travel across the borders of the state when they are reporting emissions only for California. For the purposes of reporting California emissions to the Registry, participants will report the total GHG emissions for mobile sources based in California regardless of whether the mobile sources travel outside of the state or not. Vehicles registered by the California Department of Motor Vehicles should be considered to be based in California.

Total fuel purchases for the mobile sources should serve as the basis for estimating emissions for California, regardless of where the fuel is purchased. If the distance vehicles travel is used to estimate emissions, rather than the quantity of fuel consumed, then the total distance traveled by the vehicles based in California should be used to estimate emissions. An analogous approach would be used for estimating emissions at the national level; total emissions from vehicles based in the U.S. would be reported.

The example of an interstate trucking company that has a fleet based in California illustrates how reporting would work. Purchases of diesel fuel to operate the trucks owned by the participant are made both within the State of California and outside the state. The estimation of carbon dioxide emissions would be based on the total fuels purchased for the operation of the trucks in the fleet. The emissions of methane and nitrous oxide, if they were being reported by the participant (they are optional for the first three years of reporting), would be estimated based on the total distance traveled by the trucks, or by the total fuel they consumed. This same approach would apply to all types of mobile sources: on-road vehicles, locomotives, marine vessels, and aircraft. The specific methods to estimate emissions vary based on the type of mobile source and are detailed in Section 3.1.2.

Discussion

The following sections of the SB 527 legislation are directly applicable to the geographical boundary definitions of the protocol:

SEC 11 (d)

(2) Participants shall report emissions from all of their applicable sources in the state when they initially register.

(3) Participants may, and are encouraged to, at any time, register emissions from all applicable sources based in the United States, so long as this reporting meets all the other requirements established by this chapter. Those participants with emissions in other states that report California emissions only may not be able to receive equal consideration for their emissions records in future national or international regulatory regimes relating to greenhouse gas emissions. In addition, participants with operations outside of the United States are encouraged to register their total worldwide emissions baselines and annual emissions results. Within three years, the registry shall review and report to the Legislature with a recommendation on whether the registry should require, rather than encourage, participants to report all of their greenhouse gas emissions in the United States, not just California emissions.

The language of SB 527 makes it clear that participants are to report all of their emission within the state of California. It is not explicit about whether they should report California emissions separately if they choose to report emissions from all sources in the U.S.

Since it is unclear what form any future regulation of GHGs may take, to maximize the protection of participants, Registry reporting has been set up to keep Californian and U.S. emissions separate. For all participants, this will facilitate recognition of emissions and reductions in any programs that recognize only California emissions. The small additional effort in reporting at two geographic levels is outweighed by the benefit of ensuring that they may receive protection for either their California emissions or total U.S. emissions.

SB 527 is silent on how emissions from mobile sources that cross state (or U.S.) boundaries are to be handled. For reasons of transparency and ease of calculation, emission estimates of mobile sources are to be based on fuel purchases for vehicles that are based in California. Because emissions are based on fuel purchases by the participant, data should be readily available and double counting would be minimized.

It should be recognized that the approach suggested for Registry reporting is inconsistent with the approach to geographic boundaries contained in programs to control conventional air pollutants in the state. The California Air Resources Board incentive program, for example, requires emission estimations to be based on the physical operation of mobile sources with specific geographical boundaries of the State of California (see Table 2.4 and Appendix B). Similarly, Bay Area Air Quality Management District Emissions Credit Banking Program focuses on emissions that occur within the air quality management district, and may discount or disallow completely trades that result in emissions reductions outside of the district.

The CARB approach is appropriate for conventional air pollutant because it is aimed at addressing local or regional air pollution problems. Since the location of GHG emissions does not matter, this type of approach is unnecessary for GHG emissions. Furthermore, reporting of emissions at this level of detail would be extremely burdensome for participants, because it would require them to separate out their in state and out of state emissions. Therefore the CARB approach was not recommended for Registry Reporting. It should also be noted that SB 527 does not restrict reporting of emissions from mobile sources to those emissions that occur when operating within the state of California.

Additional Registry reporting requirements for indirect transportation-based emissions are to be addressed by mid-year 2003 according to SB 527:

> SEC. 16. 42870 The State Energy Resources Conservation and Development Commission shall do all of the following:
>
> > (2) By July 1, 2003, recommend to the registry for possible adoption a procedure for defining and measuring transportation-based emissions associated with registry participants' activities, including, but not limited to, shipping of products and materials, employee commuting, and purchased air travel.

These types of emissions would raise the similar questions to the direct transportation emissions of participants. How these emissions should be counted will be described in future Registry guidance.

3.0 Emissions Estimation

Once Registry participants determine the boundaries of their inventories, they will then have to quantify the emissions for the applicable sources that fall within those boundaries. Participants will calculate and report their emissions in mass terms for each GHG. These GHGs may include:

- Carbon dioxide (CO_2),
- Methane (CH_4),
- Nitrous Oxide (N_2O),
- Hydrofluorocarbons (HFCs),
- Perfluorocarbons (PFCs), and
- Sulfur Hexafluoride (SF_6)

During the first three years of participation in the Registry, participants are required to report material emissions only of CO_2. After three years, they are required to report material emissions of each of these gases.

Greenhouse gas emissions are sometimes reported on a normalized basis instead of, or in addition to, reporting in absolute terms. Normalized emissions are emissions divided by some measure of output for the reporting entity. The specific output measure depends on the nature of the organization that is reporting and may range from physical units of output (e.g., pound of cement for a cement plant) to economic output (e.g., dollars of revenue for a diversified manufacturer). Reporting normalized emissions allows trends in the emissions intensity of an activity to be gauged by removing the effects of changing outputs on the results.

The Registry is in the process of developing output measures appropriate for a range of participants. For the purposes of this general protocol, emissions estimation and reporting guidance is provided only for reporting absolute emissions. This chapter describes procedures for estimating emissions from sources that may be found across a wide spectrum of participants.

3.1 Direct Combustion Emissions

3.1.1 Stationary Sources

Stationary combustion sources can be defined as non-mobile sources emitting pollutants resulting from fuel combustion. Typical large stationary sources include power plants, refineries, and manufacturing facilities. Smaller stationary sources include commercial and residential furnaces. Most large stationary sources in California emitting criteria pollutants such as NO_x and CO must receive permits to operate from their local air quality districts.

Estimation of Direct Emissions from Stationary Sources

The recommended estimation procedures for direct greenhouse gas emissions from stationary combustion sources are based on the methods given in the Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (CEC, 2001). In some cases, such as for the conversion of CH_4 and N_2O emission factors from a net to a gross heating value basis, modifications were made to make the methods easier for participants to use.

Emission factors derived from the state inventory should be considered to be defaults for reporting to the Registry. If participants have not conducted inventories in the past, they should use the factors given in this protocol for calculating emissions. If they already conduct GHG emissions inventories that are based on factors from the sources listed below, they may continue to use those factors instead of the Registry factors. These sources include:

- U.S. EPA, Compilation of Air Pollutant Emission Factors AP-42, http://www.epa.gov/ttn/chief/ap42/
- U.S. EPA Emissions Inventory Improvement Program (EIIP) *Introduction to Estimating Greenhouse Gas Emissions: Volume VII* (EIIP, 1999), http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html
- IPCC *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Greenhouse Gas Inventories Reference Manual* (IPCC, 1996), and
- UK Department for Environment, Food, and Rural Affairs. *Guidelines for the Measurement and Reporting of Emissions in the UK Emissions Trading Scheme*. (DEFRA, 2001).

If participants choose a source of emissions factors published outside of the United States, they will have to ensure that the emission factors are expressed on the same basis as their fuel consumption. Fuel heating values and emission factors in the U.S. are typically based on the higher heating value of the fuel, while in other countries they are based on the lower heating value. So long as participants are consistent in the basis of their emission factors in and heating values and use the same set of emission factors consistently, they may use any of the sources listed above. In addition if they have emission factors that are more accurate for the fuels and combustion devices in which they are burned, they may use those factors.

The following step-by-step instructions detail the recommended methodology for estimating emissions from stationary sources:

Step 1: Identify all types of fuel directly combusted in your operations.

For most participants, fuel will consist of natural gas, liquid petroleum fuels, and possibly coal. Petroleum fuels includes gasoline, distillate (diesel) fuel, aviation gasoline, jet fuel, kerosene, liquefied petroleum gas, and residual fuel oil.

Step 2: Identify annual consumption of each fuel.

This can be done by simply recording fuel purchase invoices and calculating your annual average consumption. If you store fuel, use Equation 3.1 to determine your annual consumption.

Equation 3.1:
Annual Consumption = Total Annual Fuel Purchases + Amount Stored at Beginning of the Year – Amount Stored at Year End

Step 3: Select the appropriate emission factor for each fuel.

Each fuel type has specific CO_2, CH_4, and N_2O emission factors. While for CO_2 emissions, these factors depend almost completely on the carbon content of the fuel alone, for CH_4 and N_2O they depend on the type of device and the combustion conditions. Table 3.1 provides the CO_2 emission factors for the most common fuel types in kilograms of CO_2 per million Btu (MMBtu) and on a per gallon basis for the petroleum fuels. Table 3.1 also provides the fraction of carbon oxidized, which is used to estimate the post combustion CO_2 emissions. Unless participants have specific information to indicate that the carbon content of a listed fuel they burn differs from that indicated in Table 3.1, or unless they are using emission factors from one of the sources listed above, they should use the emission factors presented in this table to calculate CO_2 emissions. Participants who burn fuels not listed in Table 3.1, such as refinery fuel gas, should estimate emissions based on a the specific properties of the fuel they are burning and document their emission factors in their reporting.

Table 3.1 CO_2 Emission Factors by Fuel Type

Fuel	Carbon Dioxide Emission Factor		Fraction of Carbon Oxidized
	Kg CO_2/ MMBtu	Kg CO_2/ gallon	Percent
Coal–California/United States			
Residential Coal (1999)	92.58/94.71		99
Commercial Coal (1999)	92.58/94.71		99
Industrial Coking Coal (1999)	NA/93.76		99
Industrial Other Coal (1999)	92.80/93.89		99
Utility Coal (1999)	NA/92.80		99
Natural Gas	53.05		99.5
Petroleum			
Aviation Gasoline	69.19	8.32	99
Distillate Fuel	73.18	10.15	99
Jet Fuel, Kerosene	72.35	9.77	99
Jet Fuel, Naphtha	73.18	9.33	99
Kerosene	72.35	9.77	99
Liquefied Petroleum Gas (LPG)	62.87	6.00	99

Fuel	Carbon Dioxide Emission Factor		Fraction of Carbon Oxidized
	Kg CO_2/ MMBtu	Kg CO_2/ gallon	Percent
Motor Gasoline	71.18	8.90	99
Residual Fuel	78.83	11.80	99
Propane		5.70	99.5
Butane		6.52	99.5
Methanol (neat)		4.11	99

Source: EIIP, Volume VIII, Chapter 1, except as noted below.
Note: Emission factors are based on complete combustion. Emission factors for coking and utility coals are not given for California because these types of coal are not consumed in the state. Propane and butane emission factors and fractions oxidized from U.S. EPA AP-42. Methanol emission factor is calculated from the properties of the pure compounds; the fraction oxidized is assumed to be the same as for other liquid fuels.

Table 3.2 presents the CH_4 and N_2O emission factors by activity sector and fuel type in kilograms per million Btu. These factors should be used as defaults by participants who choose to report CH_4 and N_2O emissions during their first three years of participation in the Registry, or who are required to report them thereafter, unless participants have specific emission factors they believe are more accurate or are using emission factors from one of the sources listed above. For petroleum products, CH_4 and N_2O emission factors are also shown in kilograms per gallon in Table 3.3.

Table 3.2 CH_4 and N_2O Emission Factors by Sector and Fuel Type in Kg/MMBtu

Sector	Fuel	CH_4	N_2O
		Kg CH_4 /MMBtu	Kg N_2O/MMBtu
Electric Utilities	Coal	0.0010	0.0014
	Petroleum	0.0030	0.0006
	Natural Gas	0.0010	0.0001
	Wood	0.0300	0.0040
Industrial	Coal	0.0100	0.0014
	Petroleum	0.0020	0.0006
	Natural Gas	0.0050	0.0001
	Wood	0.0300	0.0040
Commercial/ Institutional	Coal	0.0100	0.0014
	Petroleum	0.0100	0.0006
	Natural Gas	0.0050	0.0001
	Wood	0.3004	0.0040
Residential	Coal	0.3004	0.0014
	Petroleum	0.0100	0.0006
	Natural Gas	0.0050	0.0001
	Wood	0.3004	0.0040

Source: IPCC, Reference Manual, Chapter 1.

Table 3.3 Petroleum Fuel CH_4 and N_2O Emission Factors by Sector and Fuel Type in Kg/Gallon

Sector	Fuel	CH_4 Kg CH_4 /gallon	N_2O Kg N_2O/gallon
Electric Utilities	Distillate Fuel	0.0004	0.0001
	Liquefied Petroleum Gas (LPG)	0.0003	0.0001
	Residual Fuel	0.0004	0.0001
Industrial	Distillate Fuel	0.0003	0.0001
	Kerosene	0.0003	0.0001
	Liquefied Petroleum Gas (LPG)	0.0002	0.0001
	Residual Fuel	0.0003	0.0001
Commercial/ Institutional	Aviation Gasoline	0.0012	0.0001
	Distillate Fuel	0.0014	0.0001
	Jet Fuel, Kerosene	0.0014	0.0001
	Jet Fuel, Naphtha	0.0013	0.0001
	Kerosene	0.0014	0.0001
	Liquefied Petroleum Gas (LPG)	0.0010	0.0001
	Motor Gasoline	0.0013	0.0001
	Residual Fuel	0.0015	0.0001
Residential	Distillate Fuel	0.0014	0.0001
	Kerosene	0.0014	0.0001
	Liquefied Petroleum Gas (LPG)	0.0010	0.0001
	Motor Gasoline	0.0013	0.0001
	Propane	9.1×10^{-5}	4.1×10^{-4}
	Butane	9.1×10^{-5}	4.1×10^{-4}

Source: IPCC, Reference Manual, Chapter 1, except Propane and Butane, from U.S. EPA, AP-42.

Step 4: If necessary, convert your fuel consumption to the appropriate units.

If your fuel consumption is not available in MMBtu or gallons, you will have to convert it to these units. Select a conversion factor from Table 3.4.

Table 3.4 Common Conversion Factors

To Convert From:	To	Multiply by:
Natural Gas Mcf	MMBtu	1.03
Natural Gas Therm	MMBtu	0.1
Barrels	Gallons	42

Source: EIA, Annual Energy Review 2000, Appendix A.

Step 5: Calculate each fuel's CO_2 emissions by using Equation 3.2 if the fuel consumption is expressed in MMBtu or Equation 3.3 if it is expressed in gallons.

Equation 3.2:
Total Emissions (Tonnes /Year) = Emission Factor (Kg CO_2/MMBtu) * Fraction Oxidized (%) * Fuel Consumption (MMBtu/Year)* 0.001 (Tonnes/Kg)

Equation 3.3:
Total Emissions (Tonnes /Year) = Emission Factors (Kg CO_2/Gallon) * Fraction Oxidized (%) * Fuel Consumption (Gallon/Year)* 0.001 (Tonnes/Kg)

Step 6: If you are reporting CH_4 and N_2O emissions, calculate each fuel's CH_4 and N_2O emissions by using Equation 3.4 if the fuel consumption is expressed in MMBtu or Equation 3.5 if it is expressed in gallons.

Equation 3.4:
Total Emissions (Tonnes /Year) = Emission Factors (Kg CH_4 or N_2O/MMBtu) * Fuel Consumption (MMBtu/Year)* 0.001 (Tonnes/Kg)

Equation 3.5:
Total Emissions (Tonnes /Year) = Emission Factors (Kg CH_4 or N_2O /Gallon) * Fuel Consumption (Gallon/Year)* 0.001 (Tonnes/Kg)

Carbon Dioxide Emissions Measurement

Combustion emissions of carbon dioxide are most commonly quantified based on fuel consumption and the carbon content of the fuel. This is so because purchased fuels are generally very accurately measured (see discussion below) and data on fuel use and fuel carbon content are readily available. It is far less common for carbon dioxide and other GHG emission from combustion to be measured. One exception to this generalization is electricity-generating units covered by the U.S. Environmental Protection Agency's Acid Rain Program.

Under the Acid Rain program, affected units are required to install continuous emissions monitoring systems (CEMS) for sulfur dioxide and/or nitrogen oxides emissions. These affected units are also required to report CO_2 emissions to the U.S. EPA. While EPA regulations do not require that reported carbon dioxide emissions be based on CEMS measurements, in many cases the unit operators do use CEMS to report CO_2 emissions. Participants who operate CEMS under the Acid Rain Program and use them to measure CO_2 emissions may use these results for reporting to the Registry instead of reporting emissions based on fuel consumption.

Participants who wish to use CEMS for reporting CO_2 emissions should note the following, however:

- Since CEMS typically do not analyze for methane and nitrous oxide in the flue gas, these emissions will still need to be estimated based on fuel use if they are being reported to the Registry,

- Once a participant begins to report CO_2 emissions based on CEMS results, CEMS will have to be used consistently for the affected units over the entire reporting period, and

- If changes to the CEMS methodology for calculating emissions are made (for example, to eliminate bias in CEMS measurements) these changes will have to be made to the entire reporting period to eliminate changes in the reported emissions that occur solely as a result of changes in the calculations.

3.1.2 Mobile Sources

Mobile sources are non-fixed sources of air pollution such as automobiles, motorcycles, trucks, off-road vehicles, boats, and airplanes. On-road mobile sources include vehicles authorized by the California Department of Motor Vehicles to operate on public roads. All other mobile sources are considered off-road equipment. Both on-road vehicles and off-road vehicles and equipment should be included in participant's inventories.

The procedures presented to calculate combustion-related greenhouse emissions from mobile sources are based on the methods given in the Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (CEC, 2001). The statewide inventory methodology calculates CO_2 emissions based on the quantity of fuels consumed. It calculates CH_4 and N_2O emissions based on the distance traveled by various vehicle types.

Since the procedures used for the California Energy Commission's statewide inventory are based on the U.S. national emissions inventory, these procedures are also applicable to Registry participants that report emissions for the entire United States in addition to reporting California emissions. While California reformulated gasoline has slightly different properties than regular gasoline sold in other states, the effect of this difference on greenhouse gas emissions is generally considered to be small—no greater than the normal variability in gasoline from one season to another, and this difference is not accounted for in the statewide inventory. Similarly, the effect of different emissions control technologies on California vehicles has some effect on CH_4 and N_2O emissions, but in modern vehicles, these emissions are very small compared to emissions of CO_2 even after adjusting for their global warming potential. Very few data have been collected on N_2O emissions from motor vehicles, and only a small fraction of this is for vehicles with California emissions controls. As more data become available, more precise emission factors for CH_4 and N_2O will be made available for reporting GHG emissions to the Registry.

The statewide methodology is the preferred method for calculating mobile source GHG emissions as CO_2 emissions, the primary GHG emission from mobile sources, are directly related to the fuel carbon content and the quantity of fuel consumed.

Combustion emissions of CH_4 and N_2O are less directly related to fuel composition and depend on the emission control technologies employed in the vehicle. For this reason, their emission factors are typically expressed in terms of in mass of compound emitted per distance traveled, and the preferred method of calculating these emissions is based on mileage.

It is recognized that Registry participants may have information only on the annual quantity of fuel consumed by their vehicles or only on the annual mileage accumulation. For this reason, procedures are given below for estimating emissions based either on fuel consumption or distance traveled. Emission factors given in the statewide inventory in terms of grams per kilometer were converted to grams per gallon of fuel consumed in order to allow the use of annual fuel consumption to calculate emissions.

The recommended methods for estimating CO_2 emissions are presented separately from the recommended procedures for estimating CH_4 and N_2O emissions. The procedures for estimating CO_2 emissions apply to both conventional and alternative fuel vehicles. There are however, insufficient data available at present to provide emission factors for emissions of CH_4 and N_2O from alternative fuel vehicles.

CO_2 Emissions Estimation for Mobile Sources

The preferred method for estimating CO_2 emissions, using annual fuel use, is described below as Option 1. Option 2 allows participants having only access to annual mileage information to convert the data to annual fuel consumption.

Option 1. CO_2 Emissions Estimation based on Fuel Consumption

If you have annual fuel consumption for each vehicle or total fuel consumption by vehicle category, use this method to estimate emissions.

Step 1: Identify the total annual fuel consumption by fuel type.

If you store fuel at any of your facilities, and bulk fuel purchases are used to estimate fuel consumption, use Equation 3.6 to determine your annual fuel consumption. Note that the total annual fuel purchases in Equation 3.6 should include both fuel purchased for the bulk fueling facility and fuel purchased for the vehicles at other fueling locations.

Equation 3.6:
Annual Consumption = Total Annual Fuel Purchases + Amount Stored at Beginning of the Year – Amount Stored at Year End

Step 2: Select the appropriate emission factor for each fuel and the fraction of carbon oxidized from Table 3.1 to calculate CO_2 emissions.

Step 3: Calculate CO_2 emissions using Equation 3.7:

Equation 3.7:
Total Emissions (Tonnes/Year) = Emission Factor (Kg CO_2/Gallon) * Fraction Oxidized (%) * Fuel Consumption (Gallon/Year)* 0.001 (Tonnes/Kg)

Option 2: CO_2 Emissions Estimation Based on Vehicle Mileage

If you only have annual mileage information for each vehicle, use this method to estimate CO_2 emissions.

Step 1: Identify the vehicle make, model, fuel, and model years for all the vehicles you own and operate.

Step 2: Identify the annual mileage by vehicle type.

Vehicle mileage may be converted to fuel consumption using the EPA fuel economy of the specific vehicle models in the fleet. Carbon dioxide emissions are then calculated based on the fuel consumption.

EPA fuel economy figures are available at http://www.fueleconomy.gov/feg/. Two figures are given: one for city driving one for highway driving. Participants should assume, as EPA does, that 45 percent of their mileage is highway driving and 55 percent is city driving unless they have information to indicate otherwise. Note that while this web site also provides estimates of GHG emissions, these estimates should not be used for reporting to the Registry.

Step 3 Calculate annual fuel use of each vehicle model using Equation 3.8

Equation 3.8:
Fuel use (gallons) = Total Mileage (mi) / Fuel Economy (mi/gallon)

Step 4: Select the appropriate emission factor for each fuel and the fraction of carbon oxidized from Table 3.1 to calculate CO_2 emissions.

Step 5: Calculate CO_2 emissions using Equation 3.7 based on the total consumption of each fuel type.

CH_4 and N_2O Emissions Estimation for Mobile Sources
For participants reporting CH_4 and N_2O emissions, Option 1, which is based on vehicle annual mileage, is the preferred methodology for estimating these emissions. If only annual fuel consumption is known Option 2 may be used.

Option 1: CH_4 and N_2O Emissions Estimation Based on Vehicle Mileage
If you have annual mileage information for each vehicle, use this method to estimate emissions.

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle types and emission factors by model year are shown in Table 3.5 for passenger cars, light duty trucks, heavy duty trucks, and motorcycles. The emission factors in Table 3.5 are based on mileage.

Step 2: Identify the annual mileage by vehicle type.

Step 3: Select the appropriate emission factor from Table 3.5 for each vehicle and fuel type.

Step 4: Calculate each vehicle type CH_4 and N_2O emissions by using Equation 3.9.

Equation 3.9:
Total Emissions (Tonnes/Year) = Emission Factors (Gram /Mile) * Annual Mileage (Mile/Year) * 10^{-6} (Tonnes/Gram)

Step 5. Sum the emissions over each vehicle and fuel type.
The emissions calculated by Equation 9 apply to each vehicle and fuel type. The emissions for each vehicle and fuel combination must be summed to obtain the total emissions from all mobile sources.

Option 2: CH_4 and N_2O Emissions Estimation Based on Fuel Consumption

If you only have annual fuel consumption for each vehicle, use this method to estimate CH_4 and N_2O emissions.

Step 1: Identify the vehicle types, fuel, and model years of all the vehicles you own and operate.

Vehicle types and emission factors by model year are shown in Table 3.6 for passenger cars, light duty trucks, heavy duty trucks, and motorcycles. The emission factors listed in Table 3.6 are based on fuel consumption.

Step 2: Identify the annual fuel consumption by vehicle type

Step 3: Select the appropriate emission factor for each vehicle and fuel type.

Step 4: Calculate each vehicle type CH_4 and N_2O emissions by using Equation 3.10.

Equation 3.10:
Total Emissions (Tonnes/Year) = Emission Factors (Gram /Gallon) * Fuel Consumption (Gallons/Year) * 10^{-6} (Tonnes/Gram)

Table 3.5 Mobile Source CH_4 and N_2O Emission Factors by Vehicle and Fuel Type in g/mile

Vehicle Types/Model Years	N_2O g/mile	CH_4 g/mile
Gasoline Passenger Cars		
Model Year 1966-1972	0.02	0.22
Model Year 1973-1974	0.02	0.19
Model Year 1975-1979	0.05	0.11
Model Year 1980-1983	0.08	0.07
Model Year 1984-1991	0.08	0.06
Model Year 1992	0.07	0.06
Model Year 1993	0.06	0.05
Model Year 1994 - present	0.05	0.05
Diesel Passenger Cars		
All Model Years	0.02	0.02
Gasoline Light Duty Truck (<5750 GVWR)		
Model Year 1966-1972	0.02	0.22
Model Year 1973-1974	0.02	0.23
Model Year 1975-1979	0.07	0.14
Model Year 1980-1983	0.13	0.11
Model Year 1984-1991	0.14	0.11
Model Year 1992	0.11	0.09
Model Year 1993	0.08	0.07
Model Year 1994-	0.06	0.06
Diesel Light Duty Trucks		
All Model Years	0.03	0.02
Gasoline Heavy-Duty Vehicle (>5751 GVWR)		
Model Year 1981 and older	0.04	0.43
Model Year 1982-1986	0.05	0.42
Model Year 1985-1986	0.05	0.20
Model Year 1987	0.09	0.18
Model Year 1988-1989	0.09	0.17
Model Year 1990-2003	0.13	0.16
Model Year 2004-	0.28	0.12
Diesel Heavy Duty Trucks		
Model Year 1966-1982	0.05	0.10
Model Year 1983-1995	0.05	0.08
Model Year 1996-1999	0.05	0.06
Motorcycles		
Model Year 1966-1995	0.01	0.42
Model Year 1996-	0.01	0.21

Source: Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (CEC, 2001)

Table 3.6 Mobile Source CH_4 and N_2O Emission Factors by Vehicle and Fuel Type in g/gallon

Vehicle Type/Control Technology	N_2O	CH_4
	g/gallon	g/gallon
Gasoline Passenger Cars		
Model Year 1966-1972	2.4	0.18
Model Year 1973-1974	2.04	0.18
Model Year 1975-1979	1.64	0.76
Model Year 1980-1982	1.27	1.42
Model Year 1983	1.27	1.45
Model Year 1984-1991	1.21	1.54
Model Year 1992	1.10	1.28
Model Year 1993	0.99	1.03
Model Year 1994	0.93	0.87
Model Year 1995	0.92	0.85
Model Year 1996-	0.91	0.83
Diesel Passenger Cars		
Model Year 1966-1982	0.28	0.28
Model Year 1983-1995	0.36	0.36
Model Year 1996-1999	0.38	0.38
Gasoline Light Duty Truck (<5750 GVWR)		
Model Year 1966-1972	2.10	0.18
Model Year 1973-1974	2.12	0.18
Model Year 1975-1979	1.64	0.76
Model Year 1980-1981	1.33	1.42
Model Year 1982	1.32	1.43
Model Year 1983	1.31	1.45
Model Year 1984-1991	1.27	1.54
Model Year 1992	1.08	1.29
Model Year 1993	0.89	1.04
Model Year 1994	0.78	0.88
Model Year 1995	0.77	0.86
Model Year 1996-	0.77	0.84
Diesel Light Duty Trucks		
Model Year 1966-1982	0.22	0.43
Model Year 1983-	0.27	0.55

Table 3.6 Mobile Source CH_4 and N_2O Emission Factors by Vehicle and Fuel Type in g/gallon (continued)

Gasoline Heavy-Duty Vehicle (>5751 GVWR)		
Model Year 1981 and older	1.84	0.18
Model Year 1982-1986	1.79	0.21
Model Year 1985-1986	1.07	0.25
Model Year 1987	0.77	0.49
Model Year 1988-1989	0.95	0.55
Model Year 1990-1999	0.89	0.70
Diesel Heavy Duty Trucks		
Model Year 1966-1982	0.50	0.25
Model Year 1983-1995	0.45	0.27
Model Year 1996-1999	0.36	0.27
Motorcycles		
Model Year 1966-1995	8.76	0.18
Model Year 1996-1999	5.31	0.17

Source: Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999 (CEC, 2001)

Discussion

Uncertainty in Estimating Direct Combustion GHG Emissions

Combustion emissions of GHGs may be estimated from fuel usage or by direct measurement. In the case of carbon dioxide, the principal GHG emitted by combustion, each of these methods achieves a level of uncertainty that is typically less than for the measurement of emissions of conventional air pollutants.

Fuel consumption will be used by most emitters to estimate GHG emissions because for most emissions sources, fuel consumption data will be available while emissions measurement data will not. As discussed below, estimating CO_2 emissions from fuel usage can provide greater certainty than using emissions measurements, as long as standard fuel types and measured fuel consumption are used in the calculations.

Uncertainty in Estimating CO2 Emissions from Fuel Usage

The final calculation of the CO_2 emissions from a source or group of sources takes the form of the product of fuel consumption (MMBtu), fuel carbon content coefficient (lb C/MMBtu), and a fraction of fuel oxidized (percent). Fuel consumption, in turn, either explicitly or implicitly is the product of a fuel usage mass (lb) or volume (gallons, cubic feet) and fuel heat content (Btu/mass or volume). Thus, the uncertainty in the final reported CO_2 emissions from a source arise from uncertainties in each of these factors leading to the final calculation. Estimates of the uncertainties in each factor are discussed below.

Fuel Usage

The uncertainty in a source's fuel usage, other than that introduced through errors in fuel purchase record keeping, would arise from uncertainties introduced via inaccuracies in a fuel usage measurement device. The California Division of Measurement Standards within the California Department of Food and Agriculture has adopted the specifications, tolerances, and other technical requirements set forth in the National Institute of Standards and Technology (NIST) Handbook 44. This handbook sets acceptance and maintenance tolerances for mass, liquid volume, and hydrocarbon gas (e.g., natural gas) volume measuring devices. Acceptable maintenance tolerances, defined as applicable to equipment in actual use, are as follows:

- Vehicle, railroad car, and hopper scales : 0.2 to 0.4 percent
- Liquid measuring devices
  - Wholesale: 0.3 percent
  - Retail: 0.4 to 0.5 percent for quantities greater than 20 L
- Hydrocarbon gas vapor measuring devices: 1.5 percent under (0.985) to 3.0 percent over (1.030) the test standard

Thus, the uncertainty in source fuel usage should be less than 0.5 percent for solid and liquid fuels, and nominally less than 2 percent for natural gas fuel.

Fuel Heat Content

Natural gas consumed by sources in California is sold to the user by a state-regulated local distribution company. The pipeline gas delivered is routinely analyzed for composition and heating value, as gas customers are billed based on the energy delivered (therm or MMBtu). Thus, a source should have good knowledge of the heat content of the natural gas fuel used during a given time period. This value typically is reported on gas company invoices (bills). Thus, the uncertainty in natural gas heat content is expected to be 0.5 percent or less (5 Btu/scf out of 1,000 Btu/scf).

In contrast, the energy content of petroleum products is rarely measured by either producers, distributors, or consumers, nor is the energy content directly defined by product specifications. Nevertheless, the energy content of petroleum products correlates with the characteristics that define the product, such that standard or typical values can be defined for each product. EIA estimates that the uncertainty in the heat content of jet fuel and diesel fuel is less than 2 percent (EIA 2000). For motor gasoline it is less than 0.5 percent.

Industrial users of coal purchase this fuel on an energy-delivered basis. Thus, each coal shipment (truckload, rail shipment) is accompanied by an analysis report that specifies the heat content of the shipment. Accordingly, we estimate that the uncertainty in the heat content of the coal used by industrial source is to be less than 0.5 percent (50 Btu/lb out of 10,000 Btu/lb).

Fuel Carbon Content Coefficient

There are large variations in the per mass carbon and energy content (lb/lb or Btu/lb) of coals of various types and from various locales in the U.S. However, most of the variation in both is due to the variations in the non-combustible impurities in the coal (e.g., moisture and ash). Thus, the carbon content coefficient in lb/MMBtu shows much less variation in coals of a given rank (lignite, subbituminous, etc.). The EIA carbon content coefficients used in this protocol, as well as in other studies are based on analysis data on several thousand coal samples sorted by State of origin and coal rank. EIA estimates that the uncertainty introduced by the use of their typical coefficients to be less than 5 percent (EIA 2000).

Natural gas also varies in composition, but the range of variation is much smaller than that for coal. The EIA carbon content coefficients are based on analysis data of over 7,700 natural gas samples. Accordingly, EIA estimates that the uncertainty introduced by using this average coefficient to be 1 percent or less (EIA 2000).

For petroleum products, EIA estimates that their carbon content coefficients are accurate to within 1 to 2 percent for LPG and motor gasoline, 2 to 4 percent for jet fuel and diesel fuel, and 3 to 5 percent for residual fuel oil (EIA, 2000).

Fraction of Fuel Oxidized

In a properly operated combustion device, nearly all of the fuel carbon is oxidized to carbon dioxide. Therefore, published oxidation fractions range from 99 percent for coal to 99.5 percent for liquid fuels and natural gas. Since the fraction of carbon oxidized cannot exceed 100 percent, and since combustion devices are designed to achieve nearly complete combustion, the certainty levels associated with these values are very high. Furthermore, the uncertainty involved in these estimates is minimized based on the assumption that most of the partially oxidized fuel (HC, CO, etc.) is eventually converted to CO_2 in the atmosphere. The figures given above can be expected to be accurate to within 0.5 percent.

Total Uncertainty

Overall uncertainty can easily be estimated knowing that the relationships between the parameters and the emission rate are multiplicative. In order to estimate total uncertainty in a value with multiplicative relationships, the relative uncertainties of each term are summed. If, however, the individual errors are independent and random, those relative uncertainties may be added in quadrature to develop a narrower estimate of the total uncertainty. In addition, since we are concerned with an upper bound estimate of uncertainty, the regulatory limits for accuracy are used. The overall uncertainty estimate of the CO_2 emissions shown below for the consumption of various fossil fuels is shown below.

$$Err = \left[Err(FuelUsage)^2 + Err(HeatContent)^2 + Err(CarbonOxidixed)^2 \right]^{\frac{1}{2}}$$

Natural Gas = 2.3 percent
Gasoline = 2.1 percent
Diesel and Jet Fuel = 4.5 percent
Coal = 5 percent

Uncertainty in CO_2 Emissions Measured by Continuous Emission Monitoring Systems (CEMS)

Continuous emission monitoring systems (CEMS) are required by EPA under the Acid Rain Program of the Clean Air Act, and they may be employed on sources not covered by the Acid Rain Program. (Regulations dealing with CEMS are located in 40 CFR Part 75, and performance specifications for CEMS have been issued by EPA at 40 CFR Part 60 Appendix B.) Although CEMS have proven to be an effective tool for the monitoring of acid rain components (SO_2, NO_x), they are not required to monitor greenhouse gases. Because the measurement (or calculation) of the CO_2 concentration in the stack gas is required as part of the calculation of SO_2 and NO_x emissions, CEMS may be used to calculate CO_2 emissions. Since CEMS do not typically measure CH_4 or N_2O concentrations, an entity choosing to report CO_2 emissions results from CEMS will be required to estimate these greenhouse gases by another method (e.g. fuel usage data).

The basic concept behind CEMS is to measure flow rate and pollutant concentrations to calculate pollutant loading. The components typically are monitors for SO_2 concentration, NO_x concentration, and volumetric flow rate. A diluent gas (CO_2 or O_2) monitor is also included, as is a computer data handling system. The components of interest for greenhouse gas emissions (CO_2) are the diluent and flow rate monitors.

There are four equations provided within the relevant regulations that are used to calculate CO_2 emissions from CEMS data. Each equation corresponds to a different scenario: monitoring CO_2 concentration on a dry basis, monitoring CO_2 concentration on a wet basis, monitoring O_2 concentration on a dry basis, and monitoring O_2 concentration on a wet basis. Although the equations are different, the uncertainties in all methods are comparable.

The basic form for all of the methods is to convert the CO_2 concentration to a mass emission rate using the density of CO_2 and volumetric flow rate. If the CEMS monitors O_2 concentration, it must be converted to CO_2 concentration prior to calculating the emission rate. In all cases, the uncertainties involved are associated with measuring the flow rate and measuring the CO_2 or O_2 concentration. All other values used can be considered accurate, with the exception of the stack moisture content, which is used when calculating CO_2 emissions on a dry basis. Because uncertainties associated with monitoring moisture content are unknown, the uncertainties presented for measurements on a dry basis may be considered lower bounds.

CEMS are required to monitor CO_2 or O_2 concentrations to an accuracy of 1.0 percent. Flow rates, however, must only be monitored at an accuracy of 10 percent. According to the Acid Rain Program: Annual Progress Report, 2000, 98.6 percent of CEM systems meet the flow rate accuracy requirement (EPA 2001). The median accuracy of 2.69 percent, however is well below the limit (EPA 2001). The EPA report does not specify compliance with the CO_2 and O_2 accuracy requirements.

Overall uncertainty can easily be estimated knowing that the relationships between the parameters and the emission rate are multiplicative. In order to estimate total uncertainty in a value with multiplicative relationships, the relative uncertainties of each term are summed. If, however, the individual errors are independent and random, those relative uncertainties may be added in quadrature to develop a narrower estimate of the total uncertainty. In addition, since we are concerned with an upper bound estimate of uncertainty, the regulatory limits for accuracy are used. The overall, upper bound uncertainty estimate for CO_2 emissions measured by CEMS is shown below.

$$Err = \left[Err(Concentration)^2 + Err(Flow)^2\right]^{\frac{1}{2}}$$
$$Err = \left[(0.01)^2 + (0.1)^2\right]^{\frac{1}{2}}$$
$$Err = 0.1 = 10\%$$

In addition to the uncertainties presented above, CEMS have an additional concern of bias. Depending upon conditions in the stack flow, CEMS have been known to introduce systemic bias in reported values. This bias can be corrected, however. Federal regulations, in fact, require this bias to be corrected, and procedures for accomplishing this can be found in the regulations. Guidance for the elimination of bias is provided by EPA in its document entitled "An Operator's Guide to Eliminating Bias in CEM Systems" (EPA 1994). Users of CEMS who also correct for bias should also be aware that this may introduce additional random uncertainties in reported values. Typically, however, the additional random uncertainties are outweighed by the elimination of systemic bias.

Uncertainty in CH_4 and N_2O Emissions Estimates

Considerable greater uncertainty surrounds the estimation of emissions of methane and nitrous oxide than the estimation of carbon dioxide emissions. This is due to the uncertainty in the emission factors used to calculate emissions. Environment Canada has published estimates of confidence limits on methane emission factors for most stationary combustion sources burning natural gas to be +/- 40 percent and +/- 30 percent for stationary sources burning coal (SGA, 2000). For nitrous oxide emissions, the confidence limits are much worse for the same set of stationary sources and fuels—no better than within an order of magnitude—except for coal burning electric utilities, for which the confidence limit is given as –55 percent to plus 400 percent.

Better confidence limits are estimated for the combustion of light and heavy fuel oil. SGA (2000) reports the confidence limits for methane emission factors to be +/- 10 percent for both fuels except for methane emissions from light fuel combustion by electric utilities, for which the confidence limit is listed as within an order of magnitude. Nitrous oxide emission factor confidence limits are given as +/- 30 percent, except for the combustion of light fuel oil by electric utilities and in residential furnaces, for which the confidence interval is given as within an order of magnitude.

The high uncertainty of methane and nitrous oxide emission factors for stationary combustion sources is generally not regarded as a serious problem for conducting GHG inventories. This is because, compared to CO_2 emissions, the emissions of these compounds is quite small. Even when expressed as CO_2-equivalent emissions the emissions of methane and nitrous will generally be less than 0.5 percent of the CO_2 emissions from the same stationary source.

3.2 Indirect Emissions

3.2.1 Indirect Emissions from Electricity Use

For many companies, indirect emissions from electricity use may be the only greenhouse gas emissions that are reported to the Registry. In cases where electricity is purchased from a utility, rather than through a supply contract with an independent power producer, Registry participants can assess indirect emissions from electricity quite easily based on the quantity of electricity they consume and published emission factors for this electricity. In the case of electricity purchased directly from co-generation facilities, see Section 3.2.2 for guidance on estimating emissions.

The steps outline below describe the process for estimating indirect emissions from electricity consumption:

Step 1: Determine electricity consumption.

The required information is found on the utility bill received each month and is listed as the number of kilowatt-hours consumed. A kilowatt-hour is a metric for the energy used by electric loads, such as lights, office equipment, air conditioning, or machinery. Depending on the organization of the company and its facilities, one or more bills may be required for complete reporting. The monthly bills should be collected and the kilowatt-hours recorded by month. The total electricity consumption is then summed for the year. (Monthly accounting may be necessary in order to calculate emissions if the participant is using emission factors that vary seasonally.)

Step 2: Determine emission factors that apply to the electricity used.

Emissions per year are calculated by determining the level of greenhouse gases emitted per unit of electricity produced and multiplying this by the amount of electricity used. The level of emissions produced per unit of electricity is called an emission factor and is reported in grams per kilowatt-hour. Since emissions vary depending on the sources of fuel for the electricity (natural gas, nuclear, biomass, wind, hydrological, solar, or geothermal), the calculation requires an emission factor that is specific to the mix of fuels use to generate the electricity that the reporting entity consumes. This factor will vary with the utility or non-utility supplier of the electricity. It will also vary depending on the season and the region in which the facilities operate.

Participants should estimate their emissions based on the most representative emission factors they can obtain or their purchased electricity. If they can obtain emission factors specific to the supplier of their electricity, regardless of whether the supplier is an electric utility or independent power producer, they should use those factors in the calculation of emissions. If they are unable to obtain emission factors from their electricity supplier, they may use published emission factors. The U.S. Department of Energy has published state-average emission factors for the United States in *Updated State-level Greenhouse Gas Emission Factors for Electricity Generation* (EIA, 2001). Table 3.7 lists the emission factors from this source for California.

Table 3.7 California Average Electricity Emission Factors

Greenhouse Gas	Average Emission Factor, g/kWh
Carbon Dioxide	138
Nitrous Oxide	0.0003
Methane	0.0004

Source: EIA (2001)

Step 3: Determine total yearly emissions.

Multiply the electricity use in kilowatt-hours from Step 1 by the emission factors for CO_2, N_2O, and CH_4 from Step 2 and divide by the transmission and distribution (T&D) loss factor. This loss factor represents the fraction of the electricity that is lost between the generation station and the consumer. In 1996, the CEC estimated losses for Los Angeles DWP to be 9 percent and Southern California Edison losses at 7 percent. If they lack specific information from their electricity suppliers, Registry participants should assume an average loss of 8 percent.

The calculation shown in Equation 3.11 will generate an emissions value for each greenhouse gas in tonnes. If seasonal emission factors are being used, the total emissions should be summed for the entire year.

Equation 3.11:
Electricity Use (kWh) * Emission Factor (g/kWh) * 10^{-6} (tonnes/g)/ [1 – T&D Loss Factor (fraction)]= Total Emissions (tonnes)

Discussion:

Published indirect emissions factors for electricity consumption vary over a wide range. The California Energy Commission is currently working with Lawrence Berkeley Laboratory to develop a process for determining CO_2 emission factors for electricity consumed in California. As part of this work, they have reported published emission factors that vary by more than a factor of three, indicating the large uncertainty that can surround the estimates of indirect emissions based on published factors. Therefore, it is recommended that participants used emission factors specific to their electricity supplier whenever available.

As part of the Lawrence Berkeley work for the Commission, emission factors that vary by season and region may be developed for specific years. If these factors are calculated and reported annually by the State of California, use of these factors may represent a more accurate means for Registry participants to report emissions. Because the Lawrence Berkeley effort has not yet been completed, CO_2 emission factors using the methodology they are developing are not currently available, and thus are not listed in this report. Instead, the CO_2 emission factor is taken from the figures published in *Updated State-level Greenhouse Gas Emission Factors for Electricity Consumption* (EIA, 2001).

N_2O and CH_4 emission factors were taken from the same source. Considerably greater uncertainty surrounds these factors than the factors EIA publishes for CO_2 emissions, due to the greater uncertainty in the combustion emissions of CH_4 and N_2O, as discussed in Section 3.1. Because emissions of each of these compounds typically accounts for less than 0.5 percent of CO_2 emissions (on a CO_2-equivalent basis), however, the large uncertainty has little effect on total GHG emissions.

The emission factors given above are average factors. They are based on the existing mix of electric utility generation within the state of California. Marginal emission factors may also be calculated to indicate the what emissions will occur from increased electricity production. The figures in Table 3-13 are based on the assumption that incremental electricity will be served by natural gas power generation facilities. Since much of the State's current generation is from non-fossil fuel sources, this average factor is much lower than a marginal factor, which includes generation only from fossil fuel (natural gas) combustion sources.

Table 3.8 Marginal Electricity Emission Factors

Greenhouse Gas	Average Emission Factor, g/kWh
Carbon Dioxide	450
Nitrous Oxide	0.001
Methane	0.009

When calculating baseline emissions for the Registry, only the average emission factor is recommended. The marginal emission factors shown in Table 3.8 are provided for illustrative purposes. While useful for policy development, these factors are not recommended for assessing increases of decreases in emissions from Registry participants. The factors given in Table 3.8 are the marginal emissions for the entire system, and do not necessarily apply to the individual participants. It is not possible to attribute the marginal emissions to any particular electricity consumer.

3.2.2 Indirect GHG Emissions from Electricity and Heat Produced by Co-generation

Participants may receive electricity or heat from an on-site or nearby co-generation plant, rather than from a utility. Emissions from combined co-generation facilities (also referred to as combined heat and power plants) represent a special case of indirect emissions. This is because the emissions must be divided between heat production and electricity production when two or more different parties receive the energy streams. The total emissions cannot be attributed to both the heat and the electricity, as this would result in double counting. Therefore, the emissions must be allocated.

Based on typical efficiencies of heat and power production, for the purposes of reporting to the California Climate Action Registry, the fraction of emissions associated with electricity and heat production are as is given in Equations 3.12 and 3.13.

Equation 3.12:
Total Emissions (tonnes) * 2* Electricity Production (kWh)/[2 * Electricity Production + Heat Production (kWh)] = Emissions from Electricity Production (tonnes)

Equation 3.13:
Total Emissions (tonnes) * Heat Production (kWh)/[2 * Electricity Production + Heat Production (kWh)] = Emissions from Heat Production (tonnes)

Emission factors may then be derived from Equations 3.14 and 3.15 for electricity and heat production based on the total amount of electricity and heat produced.

Equation 3.14:
Emissions from Electricity Production (tonnes) * 1,000,000/Electricity Production (kWh) = Co-generation Electricity Emission Factor (g/kWh)

Equation 3.15:
Emissions from Heat Production (tonnes) * 1,000,000/Heat Production MMBtu = Co-generation Heat Emission Factor (g/MMBtu)

Emissions from electricity or heat produced by a co-generating facility will require more information than the kilowatt-hours or Btus consumed per month, unless the energy supplier provides emission factors as calculated above. Registry participants will have to obtain the total emissions of CO_2 (and CH_4 and N_2O if they are being reported) from the co-generation facility, as well as the total electricity and heat production.

Discussion

A variety of approaches have been proposed for dividing emissions between the heat and electricity outputs of CHPs. At present, however, there is no standard, generally established way of dividing these emissions. Various approaches have been used to allocate fuel use between the two outputs (e.g., Phylipsen, et al., 1998), and these approaches can be applied equally well to emissions. Several allocation approaches are described by Phylipsen et al. (1998):

1. On the basis of the energy contents of the products
2. On the basis of the exergy content (work potential) of the products
3. On the basis of the economic value of the products
4. By allocating emissions on the basis that all of the savings go to the electricity production (electricity emissions = total emissions – emissions that would have occurred with a conventional plant to produce the steam)
5. By allocating emissions on the basis that all of the savings go to the heat production (heat emissions = total emissions – emissions that would have occurred with a conventional plant to produce electricity)
6. By sharing the savings based on what emissions would have been for separate heat and electricity plants

Two methods for allocating emissions are presented in the WRI/WBCSD protocol (WRI, 2001). One is identical to Method 6 listed above. The other is based on the work potential of the product streams, and is essentially the same as Method 2.

Each of these allocation schemes will provide somewhat different results, which vary with the type of combined heat and power plant—steam turbine, gas turbine, or gas engine, for example. Each allocation scheme also requires information about the nature of the process for producing the energy streams, which may not be readily available to those attempting to estimate their GHG emissions.

To simplify the allocation of emissions to heat and electricity, the allocation of emissions is sometimes set by the reporting program. The UK Emissions Trading Scheme bases its allocation on the assumption that the efficiency of heat generation is twice that of electricity generation (DEFRA, 2001). This assumption amounts to a variation of Method 1 listed above. The fraction of emissions associated with electricity becomes $2E/(2E+H)$, and the fraction associated with heat production $H/(2E + H)$, where E is the quantity of electricity produced and H the quantity of steam produced, expressed in common units.

Th UK Emissions Trading Scheme method has been chosen for Registry reporting because it requires as little information as any of the methods, because it accounts for the differing efficiencies of heat and power production, and because it is already being used by one of the largest voluntary GHG reporting and reduction programs.

3.2.3 Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

Simplified and detailed estimation methodologies are shown below for estimating indirect emissions from imported steam or district heating from a conventional boiler plant (not a co-generation facility). Both methodologies are straightforward if all of the data are available. Because the more detailed methodology is more accurate it should be used if the necessary data are available. The simplified methodology should be used only if the data required for the more-detailed approach is unavailable. The simplified approach is presented as Option 1, the detailed approach as Option 2.

GHG emissions are calculated from the quantity of energy that comes from the district heating system, combined with the emission factors for the district heating plant, which depend upon the fuel type used by the plant. The approach is similar to that of direct fuel combustion described in section 3.1.1, except that the heat embodied in the steam or hot water is used to calculate fuel consumption rather basing emissions on measured fuel consumption. Loss factors for the generation and transmission of steam need to be accounted for in the conversion of heat consumption to fuel consumption. The steps listed below illustrate how emissions are calculated.

Option 1. Simplified Approach based on Assumed Efficiency

Step 1: Determine energy obtained from steam or district heating.

In the case of heating, fuel use is determined in steam thermal equivalents in MMBtu/month based on energy bills or other information sources. If heating bills are expressed in therms, they can be converted to MMBtu by multiplying by 0.1, as shown in the equation below. The monthly bills should be summed over the year to give annual consumption.

Equation 3.16:
Energy Consumption (MMBtu) = Energy Consumption (Therms) * 0.1

Step 2: Determine energy consumed by steam or district heating plant.

Once the Energy Consumption is obtained, it is divided by the system efficiency to obtain the total Energy Input to the system. If the efficiency is unknown, 75 percent can be assumed for the simplified approach.

Equation 3.17:
Energy Input (MMBtu) = Energy Consumption (MMBtu)/0.75.

Step 3: Calculate Emissions.

Because emissions will vary with fuel type, participants will have to know the type of fuel burned by the plant that is supplying them with steam or hot water. The should obtain this information from their energy supplier. Emission factors for stationary fuel combustion shown in Tables 3.1 and 3.2 apply for primary energy production. Equation 3.17 can then be applied using the Energy Input calculated in Equation 3.17.

Equation 3.18:
Total Emissions (tonnes/year) = Emission Factor (g/MMBtu)*Energy Input (MMBtu) * 10^6 (tonnes/g)]

Option 2. Detailed Approach based on Known Efficiency

The more detailed approach to calculating emissions is based on the actual efficiency of the heating plant and distribution system, rather than assumed values. If heating bills are expressed in terms of pounds of steam/month, participants will also be able to use this more detailed approach to convert this information into MMBtu/month based on the temperature and pressure of the steam they acquire.

Step 1: Determine energy obtained from steam or district heating.

If heating bills are given in terms of Btus, or Therms, calculate the energy consumption as described above for Option 1, Step 1.

If steam is billed in pounds, follow the approach given below for determining energy consumption.

The temperature and pressure of the steam should either be monitored by the participant's facility or specified in the supply contract with the steam supplier. The thermal energy of the steam may be calculated using saturated water at 212 °F as the reference (API, 2001). The thermal energy consumption is then calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy of the saturated water at the reference conditions. The enthalpy of the steam can be found in any standard steam tables. The enthalpy of saturated water at the reference conditions is 180 Btu per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation 3.19.

Equation 3.19:
Energy Consumption (MMBtu) = [Enthalpy of Delivered Steam (Btu/lb) – 180 (Btu/lb)] * Mass of Steam Consumed (lbs)/1,000,000

Step 2: Determine energy consumed by steam or district heating plant.

Once the Energy Consumption is calculated, it is divided by the efficiency of the boiler and transport system to obtain the total Energy Input to the system. Equation 3.20 shows that energy input is determined by dividing the Consumption from Step 1 in by the percentage efficiency of the boiler (heat energy output/fuel energy input HHV) and accounting for thermal losses in the transport of the steam or hot water to the consumer.

Equation 3.20:
Energy Input (MMBtu) = Energy Use for Heating (MMBtu/year)/[Fractional Boiler Efficiency *(1 – Fractional Transport Losses)]

Step 3: Calculate Emissions.

The calculation of emissions is for the detailed approach is the same as for the simplified approach described above. Participants should follow Step 3 above to calculate their emissions.

Note that if transport losses or boiler efficiency vary seasonally Energy Input should be calculated by Equation 3.20 on a monthly or seasonal basis, and summed to give the total annual Energy Input for use in Step 3.

Discussion

One difficulty participants may encounter when determining the indirect emissions from heating is that they may not know the type of fuel or heat losses incurred by the facility that supplies them heat or steam. Since the fuel is likely to be natural gas in California, one option is to assume that natural gas boiler was used to generate the heat and calculate GHG emissions accordingly. The type of fuel used, the boiler efficiency, and transport losses should be obtained from the energy supplier, however, to provide more accurate emissions estimates.

3.2.4 Indirect GHG Emissions from District Cooling

A simplified and a more detailed estimation methodology are presented below for evaluating indirect GHG emissions from district cooling. The simplified approach is based on an assumed coefficient of performance (COP), which is the ratio of cooling produced to energy input for the cooling plant. COPs for chillers vary by more than an order of magnitude, and therefore the simplified methodology can only be used to provide a rough emissions estimate, unless the participant can obtain the COP for the plant from which it obtains cooling.

The more detailed evaluation of GHG emissions from district cooling entails the attribution of emissions from the cooling plant to the participant's cooling demand. This is done by scaling the total GHG emissions from the cooling plant by the fraction of the total cooling demand for which the participant is responsible.

For both the simplified and detailed estimation approaches, participants will use the amount of cooling indicated on their cooling bill, which are typically specified in terms of ton-hours of cooling. Using this information, indirect GHG emissions from the district cooling can then be calculated using one of the methods given below.

Option 1. Simplified Approach based on Assumed Coefficient of Performance

Step 1: Determine Annual Cooling Demand

The cooling bill will typically report cooling demand in ton-hour. This value needs to be converted to MMBtus. (In some cases, the cooling demand may be billed in MMBtus of cooling.)

Equation 3.21:
Cooling Demand (MMBtu) = Cooling Demand (Ton-Hours) * 12,000 (Btu/Ton-Hour) * 10^{-6}

Step 2. Select COP for Cooling System

This simplified estimation methodology is dependant on the cooling system COP. The district cooling plant should be contacted to obtain the COP for the facility supplying the participant. If the participant cannot obtain the COP, it should determine the type of chiller used by the district cooling plant. With that information, a rough estimate of the COP may be selected from one of the typical values shown in Table 3.9.

Table 3.9 Typical Chiller Coefficients of Performance

Equipment Type	COP	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine Driven Compressor	1.2	Natural Gas
Electric Driven Compressor	4.2	Electricity

Using the COP, the Energy Input to the system resulting from the participant's cooling demand can be obtained. This input energy is then used to calculate emissions.

Equation 3.22:
Energy Input (MMBtu) = Cooling Demand (MMBtu) / COP

For an electric driven compressor, convert the energy input in MMBtu into kilowatt-hours by multiplying by 293.

Step 2. Calculate Emissions

If the cooling plant uses an electrically driven compressor, calculate emissions using the procedures described in Section 3.2.1 based on the amount of electricity consumption calculated by Equation 3.22.

For Absorption Chillers or Engine Driven Compressors participants should attempt to determine what fuel they consume. If the fuel type cannot be determined, assume natural gas as listed in Table 3.9. Emissions should then be calculated as described in Section 3.1.1 based on the amount of primary energy input calculated by Equation 3.22.

Option 2. Detailed Approach based on Cooling Plant Emissions and Participant's Share of Total Cooling Demand

The detailed approach to estimating indirect emissions from district cooling is based on the scaling the total cooling plant emissions by the fraction of the cooling that is provided to the participant.

Step 1. Determine total cooling-related emissions from the district cooling plant

District cooling plants take a variety of forms, and may produce electricity, hot water, or steam for sale, as well as producing cooling. In the simplest case, all of the fuel consumed by the plant is used to providing cooling. The total cooling plant emissions can then be expressed as:

Equation 3.23:
Indirect Emissions from Cooling Plant Electricity and Heat Consumption (tonnes) + Emissions from Cooling Plant Direct Fuel Combustion (tonnes) = Total Cooling Emissions (tonnes)

The process for calculating the direct and indirect emissions used in this equation is identical to those describes in the earlier sections of this chapter. The participant will either have to obtain the emission values from the district cooling plant, or calculate the emissions based on the fuel consumption and electricity and steam consumption information provided by the plant.

In many, if not most cases, the simple situation described above will not apply. Instead, the cooling plant will be integrated into a combined heat and power plant, where some of the steam and electricity produced by the plant may be used for cooling, and some may be used for other purposes. In this case, the emissions from the combined heat and power plant will need to be allocated between heating and electricity production (or shaft work in the case of internal combustion engines), and these emissions will have to be scaled by the fraction of the heat or electricity that is used for cooling, as opposed to being used for other purposes. The attribution of emissions to the heat and power streams is done in the same manner as described in Section 3.2.2.

Equation 3.24:
{Fraction of CHP Electricity Production Used for Cooling * 2* Electricity Production (kWh)/[2 * Electricity Production (kWh) + Heat Production (kWh)] +
Fraction of CHP Heat Production Used for Cooling (kWh) * Heat Production (kWh)/[2 * Electricity Production + Heat Production (kWh)]} * Total CHP Emissions (tonnes) = Total Cooling Emissions (tonnes)

If the combined heat and power plant is based on an internal combustion engine and produces shaft work, rather than electricity, the quantity of shaft work, expressed in kWh, should be substituted for the electricity production in Equation 3.24. Similarly, the heat production value in this equation applies whether the steam or hot water is produced.

Step 3: Determine fraction of cooling emissions attributable to participant.

The next step in calculating cooling emissions is to scale the total plant cooling emissions by the faction of cooling demand that the participant is responsible for. This is done by scaling the total cooling load on the plant by the cooling load of the participant.

Equation 3.25:
Total Cooling Emissions (tonnes) * Participant Cooling Load (ton-hrs)/Total Cooling Load (ton-hrs) = Participant Cooling Emissions (tonnes)

Step 4: Determine total yearly emissions.

For each month (or longer period) of the year, cooling emissions should be calculated as described in Steps 1 and 2. The duration of the periods for which the emissions are calculated will depend on the data available. Ideally, calculations would be made monthly for cooling plants integrated with CHPs, as emissions associated with cooling will depend on how the CHP outputs are distributed. If data for making these calculations are not available on a monthly basis, then longer periods will be used. In either case, the emissions for each period must be summed over the year to give the annual total.

Discussion

Cooling systems may employ a range of technologies and thus have a wide range of coefficients of performance. The mix of electricity and natural gas use for the cooling plant will have a significant impact on GHG emissions. Unlike district heating plants, emissions cannot be accurately calculated based on assumptions about the type of fuel consumed and the technology employed.

The calculation of district cooling emissions will require the cooperation of the cooling plant in supplying the required information to make the calculations. Most consumers of district cooling are, however, expected to exist within a single reporting entity, such as a college campus and thus would not require any attribution of emissions. In other cases, the plants serve related entities, such as a group of government agency buildings, and thus the required data should be available.

3.2.5 Emissions Associated with Energy Exports

Consistent with the practice of accounting for emissions associated with imported energy, emissions associated with the production of electricity, steam, heating, and cooling that are sold to another party should also be reported by Registry participants so that the emissions may be subtracted from the participant's total emissions. The calculation of exported emissions follows the same basic approach as the allocation of emissions for cooling. The total emissions associated with the electricity, heating, steam production, or cooling provided by the participant's plant are scaled by the fraction of the resources that are exported in a manner analogous to equation 3.21.

Equation 3.26:
Total Emissions (from electricity generation, heating, steam production, or cooling) * Fraction of Energy Exported (electricity, heating, steam, or cooling) = Exported Emissions (from electricity generation, heating, steam production, or cooling)

As discussed in the reporting chapter, emissions from exported energy resources, as well as energy imports, are reported separately, so the total net emissions of the participant may be calculated.

Example Emissions Calculation: ABC Manufacturing Company

ABC Manufacturing Company owns two manufacturing plants, Plant A and Plant B, both in the state of California. The company's headquarter offices are adjacent to Plant A.

ABC Manufacturing Company's headquarters and the plants operate mainly on electricity, although at Plant A, natural gas is burned in a furnace for process heating. Backup electricity is provided at Plant B by a diesel generator. Diesel fuel for the backup generator is kept in a small storage tank on site. Plant B also imports steam from a neighboring facility.

ABC Manufacturing Company operates a fleet of heavy-duty diesel trucks to distribute its products to bulk retailers throughout the region. The heavy-duty fleet is based out of Plant B where the company's fueling station and maintenance garage are situated. ABC Manufacturing Company also owns several light duty trucks. Gasoline fueling is available at Plant B, however employees often fuel at other locations. Employees are issued company gas credit cards for their offsite fuel purchases.

Direct Emissions from Stationary Sources

Step 1: Identify all types of fuel directly combusted in your operations

Fuel	Equipment Type	Number	Location
Natural Gas	Furnace	1	Plant A
Diesel	2 MW Backup Internal Combustion Generator	1	Plant B

Step 2: Identify annual consumption of each fuel

Fuel	Equipment Type	Number	Location	Annual Fuel Purchase	Fuel stored January 1	Fuel stored December 31
Natural Gas	Furnace	1	Plant A	125,000 MMBtu	N/A	N/A
	Total Fuel Consumption			**125,000 MMBtu/year**		
Diesel	Backup Internal Combustion Generator	1	Plant B	1,200 gallons	500 gallons	200 gallons
	Total Fuel Consumption			**1,500 Gallons/year**		

Calculate the total diesel consumption using Equation 3.1

Total Diesel Consumption = (1,200 + 500 – 200) gallons
= 1,500 gallons/year

Step 3: Select the appropriate emission factors for each fuel from Tables 3.1 and 3.2

Step 4: As fuel consumption is in the appropriate units, this step can be bypassed.

Step 5: Calculate each fuel's CO_2 emission contribution

Natural Gas CO_2 emissions = 53.05 kg/MMBtu * 99.5% * 125,000 MMBtu/year * 0.001 Tonnes/kg
= 6,600 Tonnes/year

Diesel CO_2 emissions = 10.15 Kg/gallon * 99%* 1,500 gallons/year * 0.001 Tonnes/kg
= 15 Tonnes/year

Step 6: Calculate each fuel's CH_4 and N_2O emission contribution

Natural Gas CH_4 emissions = 0.005 kg/MMBtu * 125,000 MMBtu/year * 0.001 Tonnes/kg
= 0.63 Tonnes/year

Natural Gas N_2O emissions = 0.0001 kg/MMBtu * 125,000 MMBtu/year * 0.001 Tonnes/kg
= 0.013 Tonnes/year

Diesel CH_4 emissions = 0.0003 kg/gallon * 1,500 gallons/year * 0.001 Tonnes/kg
= 0.00045 Tonnes/year

Diesel N_2O emissions = 0.0001 kg/gallon * 1,500 gallons/year * 0.001 Tonnes/kg
= 0.00015 Tonnes/year

Fuel	CO_2 (Tonnes/year)	CH_4 (Tonnes/year)	N_2O (Tonnes/year)
Natural Gas	6,600	0.63	0.013
Diesel	15	0.00045	0.00015
Total	**6,615**	**0.63**	**0.013**

Direct Emissions from Mobile Sources

Vehicle Type	Fuel	Model year	Number	Usage data available (Data source)
Heavy Duty Vehicles	Diesel	1995	15	Fuel Use (On-site fuel delivery) Mileage (Driver mileage log)
Light Duty Trucks	Gasoline	1997	4	Fuel Use (On site fuel delivery, credit card statements) Mileage (Driver mileage log)

CO_2 Emission Calculation

Option 1 is selected because fuel use data is available

Step 1: Identify the total annual fuel consumption by fuel type

Vehicle Type	Fuel	Model year	Number	Annual Fuel Purchased per Fleet	Fuel Stored January 1	Fuel stored December 31
Heavy Duty Vehicles	Diesel	1995	15	165,000 Gallons/year	2,500 Gallons	5,500 Gallons
			Total	**162,000 Gallons/year**		
Light Duty Trucks	Gasoline	1997	4	4000 Gallons/year	500 Gallons	250 Gallons
			Total	**4,250 Gallons/year**		

Total Diesel Consumption = (165,000 + 2,500 – 5,500) Gallons
= 162,000 Gallons/year

Total Gasoline Consumption = (4,000 + 500 – 250) Gallons
= 4,250 Gallons/year

Step 2: Select the appropriate emission factor for each fuel from Table 3.5

Step 3: Calculate each fuel's CO_2 emission contribution

Diesel CO_2 emissions = 10.15 kg/gallon * 99%* 162,000 gallons/year * 0.001 Tonnes/kg
= 1,630 Tonnes/year

Gasoline CO_2 emissions = 8.9 kg/gallon * 99%* 4,250 gallons/year * 0.001 Tonnes/kg
= 37 Tonnes/year

CH_4 and N_2O Emissions

To calculate CH_4 and N_2O emissions, the preferred methodology Option 1 requiring mileage information is used.

Step 1: Identify vehicle type, fuel, and model year of each vehicle

Vehicle Type	Fuel	Model year	Number
Heavy Duty Vehicles	Diesel	1995	15
Light Duty Trucks	Gasoline	1997	4

Step 2: Identify the annual mileage by vehicle type

Vehicle Type	Fuel	Model year	Number	Annual Mileage by Vehicle	Annual Mileage by Type
Heavy Duty Vehicles	Diesel	1995	15	60,000 Miles/year	900,000 Miles/year
Light Duty Trucks	Gasoline	1997	4	15,000 Miles/year	60,000 Miles/year

Step 3: Select the appropriate emission factor for each fuel and vehicle type from Table 3.5

Step 4: Calculate each vehicle type CH_4 and N_2O emission contributions

Heavy Duty Diesel Vehicles

HDV(Diesel, 1995) N_2O Emissions = 0.05 g/mile * 900,000 miles/year * 10^{-6} Tonnes/g
= 0.045 Tonnes/year

HDV(Diesel, 1995) CH_4 Emissions = 0.08 g/mile * 900,000 miles/year * 10^{-6} Tonnes/g
= 0.072 Tonnes/year

Light Duty Trucks

LDT(Gasoline, 1997) N_2O Emissions = 0.06 g/mile * 60,000 miles/year * 10^{-6} Tonnes/g
= 0.0036 Tonnes/year

LDT(Gasoline, 1997) CH_4 Emissions = 0.06 g/mile * 60,000 miles/year * 10^{-6} Tonnes/g
= 0.0036 Tonnes/year

Vehicle Type	Fuel	Model year	CO_2 (Tonnes/year)	CH_4 (Tonnes/year)	N_2O (Tonnes/year)
Heavy Duty Vehicles	Diesel	1995	1,630	0.072	0.045
Light Duty Trucks	Gasoline	1997	37	0.0036	0.0036
		Total	**1,670**	**0.076**	**0.049**

Indirect Emissions from Imported Energy

Before calculating indirect emissions, all types of indirect emissions related to ABC manufacturing Company must be identified:

Source	Location
Electricity Consumption	Plant A and B, Headquarters (HQ)
Steam Consumption	Plant B

Step 1: Identify annual consumption and suppliers of steam and electricity

Source	Location	Annual Purchase	Supplier
Electricity	Plant A	1,200,000 kWh	Grid
Electricity	Plant B	1,200,000 kWh	Independent Power Producer (not a co-generator)
Electricity	HQ	100,000 kWh	Grid
Steam	Plant B	6,000 Therms	Conventional Steam Generator (gas-fired)

Note that if the emission factors for electricity production vary throughout the year, the calculations in Step 2, 3, and 4 should be done on a monthly basis and then summed at the end rather than determining emissions from annual purchases. Although the emissions are assumed to be uniform throughout the year in this example, Section 3.2.1 provides steps to follow if emissions vary seasonally.

Step 2: Determine emission factors and T&D loss factors that apply to electricity consumed

The company was unable to receive specific information from the utility serving Plant A and its headquarters on emissions and T&D losses. Therefore, it bases its emissions estimates on the default values. For Plant B, however, it was able to obtain emission factors and T&D loss factors from the independent power producer (IPP) with which it has a supply contract to serve the plant.

Source	T&D Loss Factor	Emission Factors, g/kWh generated			Source of Emission Factors
		CO_2	CH_4	N_2O	
Grid	8%	250	0.0004	0.0003	From Table 3.12
IPP	1% (supplied by IPP)	400	0.0007	0.0005	Supplied by IPP

Step 3: Calculate emissions from each source of electricity supply

Plant A + HQ electricity CO_2 emissions = (1,200,000 + 100,000) kWh * 250 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.08)]
= 350 Tonnes/year

Plant B electricity CO_2 emissions = 1,200,000 kWh * 400 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.01)]
= 480 Tonnes/year

Plant A + HQ electricity CH_4 emissions = (1,200,000 + 100,000) kWh * 0.0004 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.08)]
= 0.00057 Tonnes/year

Plant B electricity CH_4 emissions = 1,200,000 kWh * 0.0007 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.01)]
= 0.00085 Tonnes/year

Plant A + HQ electricity N_2O emissions = (1,200,000 + 100,000) kWh * 0.0003 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.08)]
= 0.00042 Tonnes/year

Plant B electricity N_2O emissions = 1,200,000 kWh * 0.0005 g/kWh * 10^{-6} Tonne/g * [1 / (1 – 0.01)]
= 0.00061 Tonnes/year

Facility	Source	CO_2 (Tonnes/year)	CH_4 (Tonnes/year)	N_2O (Tonnes/year)
Plant A + HQ	Grid	350	0.00057	0.00042
Plant B	IPP	480	0.00085	0.00061
	Total	**830**	**0.00142**	**0.00103**

To calculate emission from the consumption of steam, the participant would follow the following steps. Aside from knowing that the steam is supplied by a conventional steam generator fueled by natural gas, the participant has other information about the supplier.

Step 1: Determine energy obtained from steam or district heating in MMBtu.

Steam energy consumed = 6,000 Therms * 0.1 MMBtu/Therm = 600 MMBtu/year

Step 2: Determine emissions that apply to fuel used to generate the steam

Since the participant knows natural gas is used to generate the steam, emissions factors in terms of MMBtu for natural gas from Tables 3.1 and 3.2 are employed. An average boiler efficiency of 85 percent, and a loss factor of 6% are used lacking any more specific information.

Facility B steam CO_2 emissions = 600 MMBtu * 53 kg/MMBtu * 10^{-3} Tonne/kg * [1 / (0.85)] * [1 / (1-0.06)]
= 40 Tonnes/year

Facility B steam CH_4 emissions = 600 MMBtu * 0.005 kg/MMBtu * 10^{-3} Tonne/kg * [1 / (0.85)] * [1 / (1-0.06)]
= 0.0038 Tonnes/year

Facility B steam N_2O emissions = 600 MMBtu * 0.0001 kg/MMBtu * 10^{-3} Tonne/kg * [1 / (0.85)] * [1 / (1-0.06)]
= 0.000075 Tonnes/year

Facility	Source	CO_2 (Tonnes/year)	CH_4 (Tonnes/year)	N_2O (Tonnes/year)
Plant B	Steam	40	0.0038	0.000075
	Total	**40**	**0.0038**	**0.000075**

Emissions Summary for ABC Manufacturing Company

Source	CO_2 (Tonnes/year)	CH_4 (Tonnes/year)	N_2O (Tonnes/year)
Direct Emissions from Stationary Sources			
Natural Gas	6,600	0.63	0.013
Diesel	15	0.00045	0.00015
Direct Emissions from Mobile Sources			
Diesel	1,630	0.072	0.045
Gasoline	37	0.0036	0.0036
Indirect Emissions			
Electricity – Grid	350	0.00057	0.00042
Electricity – IPP	480	0.00085	0.00061
Steam	40	0.0038	0.000075
Total Emissions	**9,150**	**0.71**	**0.063**
Global Warming Potential	1	21	310
Total Emissions in CO_2 Equivalents	**9,150**	**15**	**19**

This example illustrates the small contribution methane and nitrous oxide make to combustion emissions. Together, these two compounds amount to less than 0.4 percent of total emissions express on a CO_2-equivalent basis. Assuming the participant has no other emissions that it considers de minimis, these compounds could be excluded from Registry reporting even after the participant had been reporting for more than three years, when reporting of all GHGs is normally required.

3.3 General Fugitive Emissions of GHGs

Most fugitive emissions of GHGs are specific to various industrial sectors or processes. One emissions source that is common across a wide range of entities is leakage from refrigeration systems. Since not all refrigerants are GHGs, only those that contain or consist of compounds on the Registry's list of greenhouse gases are of interest for reporting. Hydrofluorocarbons (HFCs) are the primary GHG of concern for refrigeration systems, particularly for motor vehicle air conditioners. Today HFC-134a is the standard refrigerant for mobile air conditioning systems.

For most Registry participants, emissions of HFCs from air conditioning systems will be negligible in comparison to other GHG emissions. This will be true even when the high global warming potentials of HFCs are considered.

The emissions calculation process described in this section is two-tiered. The first tier is to roughly estimate emissions to determine if they are material, and thus warrant a more comprehensive review. The second tier is performing the more comprehensive review to obtain accurate HFC emissions.

To determine emissions, the following data are required:

- Types and quantities of air conditioning equipment
- Total refrigerant charge
- Annual leak rate
- Type of refrigerant

The following step-by-step instructions detail a methodology for estimating emissions HFC emissions from air conditioners:

Step 1: Determine if HFC Emissions are Material

This step is the first tier approach that allows an entity to roughly estimate emissions and determine if HFC emissions from air condition systems are material. Consistent with the registry definition of materiality, HFC emissions from air conditioners greater than or equal to five percent of a participant's total emission are considered material, assuming the participant has no other de minimis emissions. Emissions less than five percent are considered de minimis, can be ignored, and no further calculations are needed. However, if emissions are considered substantial then a more comprehensive mass balance approach is required to determine actual emissions. For a complete discussion of applying de minimis criteria, see Section 2.2.

Table 3.10 gives typical values for leakage rates, refrigerant charges, and type of refrigerant for various refrigeration systems. This information may be used for Step 1.

Using the values in Table 3.10, the following formula is used to obtain emissions estimates:

$$\text{HFC Emissions from Annual Air Conditioning C (kg)} = \sum (\text{Refrigerant Charge (kg)} \times \text{Annual Leak Rate (\%)})$$

The emissions from each unit are added together to achieve the total emissions of each type of HFC. If the HFC emissions are material, continue to Step 2.

As discussed in Section 2.2, the global warming potential for each HFC must be multiplied by the corresponding mass emission rate. If the sum of the HFC CO_2-equivalent emissions and other participant emissions considered to be de minimis is less than 5 percent of the total emissions, the HFC emissions are not required to be reported.

Table 3.10 Air Conditioner Loss Rates[1]

Type of AC System	Annual Loss Rate, %	Refrigerant Charge, kg	Type of Refrigerant[2]
Large Automobile	1.3	1.0	HFC-134a
Small Automobile	1.3	0.5	HFC-134a
Residential Central Air System (3 ton)	4.5	2.8	R407C
Commercial AC System (7 ton)	2	6.9	R407C
Commercial Chiller (350 ton)	1	480	HFC-123
Commercial Chiller (350 ton)	1	432	HFC-134a
Commercial Chiller (1000 ton)	1	1,225	HFC-123
Commercial Chiller (1000 ton)	1	1,120	HFC-134a
Direct Expansion (DX) Central Refrigeration System	15	6% of floor area (ft^2)	R404A,R507
Water-Cooled Distributed System	4	0.66% of floor area (ft^2)	R404A,R507
Secondary Loop System	2	1.5% of floor area (ft^2)	R404A,R507

Note: All information included in this table is based on "Global Comparative Analysis of HFC and Alternative Technologies for Refrigeration, Air Conditioning, Foam, Solvent, Aerosol Propellant, and Fire Protection Applications." (Dieckmann, 1999). All values are estimates and are meant as guidelines and not as default values.

Several of the refrigerants listed in Table 3.10 are blends of HFCs. The composition of these blends is shown in Table 3.11.

Table 3.11 Composition of Refrigerant Blends

Blend	HFC-32	HFC-125	HFC-134a	HFC-143a
R404A	-	44%	4%	52%
R407C	23%	25%	52%	-
R507	-	50%	-	50%

Source: EPA, 1998

If the screening calculations of HFC emissions indicate that they are material, more accurate means of quantification are necessary, as outlined below.

Steps 2-4: Mass-Balance Calculation

Tier two of the calculations is the more comprehensive, mass-balance approach to obtain accurate HFC emissions. The concept behind the mass-balance approach is to calculate to total change in the HFC inventory each year. Differences from the beginning to the end of the year are assumed to be fugitive emissions.

HFCs in inventory refers to HFCs contained in cylinders and other storage containers. It does not refer to HFCs held in operating equipment. Additions and subtractions refer to HFCs placed in or removed from the stored inventory, respectively.

Step 2: Calculate Base Inventory for Each HFC

Table 3.14 Base Inventory

	Inventory	Amount (kgs)
A	Beginning of year	
B	End of year	

Step 3: Calculate Changes to Inventory

Table 3.15 Inventory Changes

Additions to Inventory		
		Amount (kgs)
1	Purchases of HFCs (including HFCs provided by equipment manufacturers with or inside new equipment)	
2	HFCs returned to the site after off-site recycling	
C	**Total Additions (add items 1-2)**	
Subtractions from Inventory		
		Amount (kgs)
3	Returns of HFCs to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and send off-site for recycling	
D	**Total Subtractions (add items 3-5)**	
Change to Nameplate Capacity		
		Amount (kgs)
6	Total nameplate capacity of new equipment	
7	Total nameplate capacity of retiring equipment	
E	**Change to nameplate capacity (subtract item 7 from 6)**	

Step 4: Calculate Total Annual Emissions

Total Annual Emissions = **A** – **B** + **C** – **D** – **E**

This approach is applied to each HFC to obtain the annual mass emissions.

Discussion

The mass balance approach presents more challenges to the participant in obtaining the necessary data than does the screening approach. In many instances the participant may not receive records of the amount of HFC added to the system when it is repaired. For example, when a consumer has a car air conditioning system charged, the consumer rarely knows the amount of HFC-134a added to the system. For the mass-balance approach to work successfully, the reporting entity must obtain all the required information. Although more burdensome than the screening approach, the mass balance approach is required for Registry reporting because it is far more accurate than the screening approach and will allow tracking of actual changes in the participant's emissions.

4.0 Emissions Reporting

Registry participants are required to report their emissions in a consistent manner to promote the accuracy, completeness, and transparency of their emissions estimates. To allow for the greatest level of compatibility with national and international emissions programs, participants must record their annual GHG emissions on a calendar year basis (January – December), though they may submit their reports to the Registry at their convenience any time after the close of the calendar year.

The three principal types of Registry reporting are:

1. Initial Registration and Baseline Establishment

2. Annual Emissions Report
   - Supporting Documentation
   - Additional Optional Emissions Information/Comments

3. Baseline Emissions Adjustments

Emissions Results

The Registry will collect and make available to the public the following information from all participants:

- All material direct and indirect emissions of CO_2 by source category consistent with a participant's defined organizational boundary and baseline

- Total gross GHG emissions

- One or more GHG emission ratios that demonstrate emission efficiency (once the Registry establishes emissions ratios)

Online Reporting

The Registry is considering requiring most reporting to take place via a Registry Application on the Internet. It believes online reporting is essential for Registry reporting among such a diverse spectrum of potential participants. Online reports will automatically customize to a participant's specific reporting needs as they enter data. In addition, future year's emission sources will be able to be easily recalled to speed reporting. The Registry expects online reporting to be a time-saving, easy way to minimize participants' staff needs for reporting.

To facilitate online reporting, participants will have access to a Registry Application Help Line, where they will be able to receive technical support for the Application. The Registry staff will assist participants with their online reporting, and will be trained to answer technical reporting questions.

Confidentiality Issues
While the Registry will make the rolled-up emissions results from all participants available to the public, each participant will have the ability to classify emissions information that could negatively impact its business processes. However, the Registry expects that the time delay associated with reporting annual emissions will likely minimize the need to classify a large amount of information as confidential.

4.1 Base Year and Baseline

In order to track emissions over time, entities must establish a starting point, or datum, against which to measure their progress. As defined by the SB 527, "**baseline** means the datum against which to measure greenhouse gas emissions performance over time, usually annual emissions in a selected base year." This definition of baseline is referred to as a static baseline. In the absence of any structural changes to the reporting entity, the baseline would remain fixed in time. This type of a baseline should not be confused with a dynamic baseline, which is the trend line of what greenhouse gas emissions would have been over time in the absence of projects to reduce emissions (WRI, 2001). (While the term baseline may more commonly be used for GHG emission reduction projects, it can also be applied to total entity emissions.)

This chapter discusses how base years and baselines are established and adjusted. It also describes how participants will report their base year and annual reporting results to the Registry.

4.1.1. Base Year

Participants in the Registry have the option of establishing a base year for any year back to 1990, providing they have sufficient data. The earliest year reported becomes a *de facto* base year. A benefit of establishing a base year before the current year might be to show reduced GHG emissions from the base year.

If a participant chooses to use a historical base year, it must have complete energy use or fuel consumption data that can be certified for past years. Without a historical base year, participants will simply begin reporting current year emissions to the Registry. In this case, the current year (the first year of reporting) would become the base year.

After establishing a base year for emissions results, participants must report their certified emissions results in each subsequent year. If a participant drops out of the Registry and returns at a later date, they must fill in the data for the missing years, or establish a new base year.

4.1.2 Baseline and Baseline Adjustments

As defined above, the baseline for reporting to the Registry is the participant's emissions for the base year it selects, or the emissions in the first year of its reporting, if it elects not to (or cannot) establish a historical base year for its baseline. The base year emissions will remain as the participant's baseline into the future unless changes to the structure of the organization or emissions estimation methodologies require that the baseline be adjusted. The purpose of these adjustments are to ensure that reported increases or decreases in emissions are truly the result of a net increase or decrease in emissions over time, and not merely the result of changes in the participant's organization or reporting method.

Changes in the organization or its reporting that will require adjustment of the baseline include:

- Acquisitions
- Mergers
- Divestitures
- Outsourcing (contracting activities previously conducted internally)
- Insourcing (conducting activities that were previously contracted)
- Shifting emissions to or from California
- Changes in emissions estimation methodologies

For many organizations, particularly large ones, mergers, acquisitions, and divestitures, as well as the other listed organizational changes, are common occurrences. Rather than requiring baseline adjustments whenever any changes —however insignificant—occur in a participant's organization, Registry participants will be required to adjust their baseline whenever the cumulative effect of such changes affects their emissions by more than five percent of the total for a reporting year.

The examples below illustrate how the baseline would be adjusted for various scenarios:

Acquisitions

If Company A, a Registry participant, acquires Company B, and this acquisition increases Company A's GHG emissions by 5 percent or more, the base year emissions should be adjusted to create a new baseline that includes Company B's base year emissions (provided Company B was in existence in the base year.) If Company B was not in existence in the base year, Company A's base year emissions would not be adjusted, and the increase in emissions would be attributed to organic growth (see below). If the acquisition if Company B led to less than a 5 percent increase in GHG emissions, the base year would not need to be adjusted unless when combined with other changes to the organization, the cumulative effect was to change the emissions by more than 5 percent.

This example presumes that Company B has data sufficient to established baseline emissions for the base year used by Company A. If this is not the case, then Company A would have to choose a new base year for which both companies have sufficient data to allow the baseline emissions to be certified.

Mergers

Mergers are treated in the same way as acquisitions.

Divestitures
Registry participant Company C, in deciding to focus on its core business, divests of its X, Y, and Z divisions over a three year period. Each of these divisions account or two percent of its GHG emissions. Because the cumulative effect of these divestitures after three years would be to reduce the company's emissions by more than five percent, Company C will have to adjust its baseline. It will do this by subtracting the base year emissions of its X, Y, and Z divisions from its baseline.

Outsourcing
If a participant contracts out activities previously included in its base year inventory, it treats these activities like a divestiture. Emissions associated with the outsourced activity would be subtracted from the baseline emissions. Also, as part of their annual reporting, participants are required to attest that they have not outsourced any emissions, or if they have, that these emissions have been subtracted from their baseline.

Insourcing
Insourcing is the opposite of outsourcing. If a participant begins to conduct business activities that it previously included in its base year inventory, it treats these activities like an acquisition. Emissions associated with the insourced activity would be added to its baseline emissions.

Shifting Emissions
For the purposes of reporting California emissions, if a participant shifts operations from other states into California, and the change in its emissions exceeds the five percent threshold, the participant will adjust its California baseline in the same manner as for an acquisition. Conversely if a participant shifts operations out of state that result in a reduction of emissions that exceed the five percent threshold, it will adjust its baseline to subtract these emissions from these operations.

If a participant reports both statewide and national emissions, changes to its base year for the purposes of national reporting will be treated in a similar manner, Shifts of operations to outside of the U.S. would result in a reduction in the baseline, shifts of operations to the U.S. would result in an increase to the baseline, provided the change threshold was exceeded. Participants would thus maintain two baselines one for California and one for the U.S. as a whole. California annual emissions results would be reported both separately and as part of total U.S. reporting.

Change in Emissions Estimation Methodologies
Baseline emissions should be adjusted for any changes in calculation methodologies if such changes will result in changing total participant emissions in the current reporting year more than 5 percent.

Organic Growth or Decline
There are no baseline adjustments for organic growth or decline. Organic growth or decline refers to increase or decrease in production output, changes in product mix, plant closures, and the opening of new plants that are not the result of changes in the structure

of the participant's organization or the result of shifting operations into or out of California (for the purpose of participants recording California-only emissions).

However, to account for expansion and growth, the Registry will be recording normalized emissions—emissions divided by output—that will allow participants to demonstrate increased efficiency even if overall emissions increase. These efficiency metrics are being developed through industry working groups.

Discussion

SB 527 establishes the possible past years and data requirements for establishing a baseline:

> SEC. 11. 42840(a) Participants shall utilize the following reporting procedures to establish a greenhouse gas emissions baseline, participants shall report their certified emissions for the most recent year for which they have complete energy use and fuel consumption data as specified in this chapter. Participants that have complete energy use or fuel consumption data for earlier years that can be certified may establish their baseline as any year beginning on or after January 1, 1990. After establishing baseline emissions, participants shall report their certified emissions results in each subsequent year in order to show changes in emissions levels with respect to their baseline year. Participants may report annual emission results without establishing an emissions baseline.

The Registry requirements related to the establishing a baseline come directly from these provisions of SB 527.

SB 527 contains several sections that specify when baseline adjustments are necessary:

> SEC. 11. 42840
>
> (4) To ensure that reported emissions reflect actual emissions, participants that outsource production or services shall report emissions associated with the outsourced activity, and remove these emissions from their emissions baseline. The subcontracted entity, if it voluntarily chooses to participate in the registry shall report emissions associated with the outsourced activities it has taken over. Participants shall attest at least once each year that the entity has not outsourced any emissions, or that if it has, that all emissions associated with the outsourced activity have been reported and subtracted from the entity's baseline emissions.
>
> (5) To prevent changes in vertical integration within corporations from leading to apparent emissions reductions when in fact no reductions have occurred, the registry shall treat mergers, acquisitions, and divestitures as follows:
>
> > (A) The emissions baselines of any merged or acquired entity shall be added together, and the registry shall treat the resulting entity as if it had been one corporation from the beginning.
> >
> > (B) In divestitures, the emissions baselines of the affected corporations shall be split, with the effect that the registry shall treat them as if they had been separate corporations from the beginning. If the divested corporation is purchased by another firm, the registry shall treat that purchase as a merger

with the purchasing corporation. If the divested corporation remains a separate entity after the divestiture, its registry baseline shall reflect the emissions associated with the entity's operations before the divestiture. Corporations that divest operations may allocate certified emissions results achieved prior to the divestiture among the divesting and the divested entities, and the registry shall adjust their baselines accordingly.

(C) Any adjustments for changes in vertical integration shall be verified in the annual emissions certifications required for recordation of emissions results.

(6) If a participant changes from statewide to national reporting under this program, changes to its baseline will be treated in a similar manner as changes in vertical integration as described in paragraph (5).

(7) To ensure that reported emissions accurately reflect shifts in operations to or from other states, the registry shall adopt, in consultation with the State Energy Resources Conservation and Development Commission, at a public meeting and following at least one public workshop, reporting procedures for participants that choose to report greenhouse emissions on a statewide basis that require participants to show both of the following:

(A) Changes in a participant's operations, such as a facility startup or shutdown, that result in a significant and long-term shift of greenhouse gas emissions from California to other states or from other states to California.

(B) The corresponding change in the participant's baseline.

The general concepts of the baseline adjustment rules of the protocol follow the SB 527 legislation. SB 527 does not specify any threshold for when baseline adjustments are required, however. Since it would be unrealistic to require baseline changes, however insignificant, whenever the structure of a participant's organization changed, five percent was chosen as a reasonable change threshold. This is higher, however, than the 2.5 percent threshold used in the UK Emissions Trading Scheme.

In addition to the provisions contained in SB 527, the inclusion of insourcing (taking over previously subcontracted activities) and the discussion of organic growth/decline and changes in calculation methods were modeled after the WRI/WBCSD protocol (WRI, 2001)

4.2 Initial Registration and Baseline Reporting

Initial registration will register an entity as a participant in the Registry. In addition to registering an entity, the initial registration process will collect the first year of emissions data from a participant. This first year's data will consequently serve as a participant's baseline.

The initial registration process will differ slightly from subsequent annual reporting processes as participants will need to supply general information and overall descriptions about their entity's activities to the Registry, in addition to their annual emissions. Since reporting is expected to be done via the Registry's Application, when participants are ready to register for the first time, the Registry will assign each participant an ID number to access the Application.

Initial Registration

In their first year of reporting, participants must describe their entity's operations, identify all of their entity's direct and indirect sources of GHG emissions, quantify the amount of fuel used by their direct sources, and calculate the gross GHG emissions and available efficiency ratios for their emissions sources. In most cases, the Registry Application will actually calculate the gross annual GHG emissions and efficiency metrics related to an entity's sector. (Participants with highly complicated direct emissions should contact the Registry to discuss alternate reporting mechanisms—email, etc.)

Information Needed for Initial Registration

Participants will need to have the following information to complete the initial registration process:

- General company information
- Participation parameters (boundaries, methods, confidentiality, etc.)
- Explanation of methodology for tracking sources of GHG emissions
- Sources of indirect emissions
    - Energy bills and/or invoices for all indirect emissions
- Sources of direct emissions by the following source categories:
    - Transportation
    - On site combustion
    - Process emissions
    - Fugitive emissions
        - Fuel records for each source category of direct emissions
- Locations and descriptions of uses for all sources of emissions
- Emissions factors for calculating GHG emissions (if not using the defaults in the Registry Application). Participants will also need to explain the methodology for using an emission factor that differs from the Registry's default.

The information to be provided to the Registry should be organized on a facility by facility basis, as is illustrated in Table 4.1. In this case, the information being provided is on the source categories included in each facility's emissions inventory. The intent of this listing is not to include each individual emission source, but rather to describe the types of emissions included within each source category—for example indirect emissions from imported electricity and steam for Facility 1 or delivery vehicle transportation emissions for Facility 2.

The purpose of the participant source category list shown in Table 4.1 is to define which sources are in the participant's baseline, allow for future adjustments of the baseline, and to facilitate certification of baseline adjustments. If a particular facility is divested, for example, it would be dropped from the source description table, and the emissions sources listed for that facility would be subtracted from the participant's baseline.

Table 4.1 Example of a Participant Source Description.

Participant		
Facility 1	**Facility 3**	**Facility 3**
Source Category 1 (Indirect Emissions)	Source Category 1 (Indirect Emissions)	Source Category 1 (Indirect Emissions)
Source Category 2 (On-site fuel combustion)	Source Category 2 (On-site fuel combustion)	Source Category 2 (On-site fuel combustion)
Source Category 3 (Transportation)	Source Category 3 (Transportation)	Source Category 3 (Transportation)
Source Category 4 (Process emissions)	Source Category 4 (Process emissions)	Source Category 4 (Process emissions)
Source Category 5 (Fugitive emissions)	Source Category 5 (Fugitive emissions)	Source Category 5 (Fugitive emissions)

The submission of documentation related to utility or fuel bills listed above would apply to those participants that will undergo simplified certification processes. For those participants, copies of the submitted documentation may serve as an alternative to site visits for conducting certification. (See Chapter 5.)

Optional Emissions Reporting

In addition to the required information for initial registration, participants are also able, and encouraged to report additional information, such as:

- Material direct emissions of methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) by source category consistent with a participant's defined organizational boundary and baseline (inclusion of these compounds is optional during a participant's first three years of reporting)

- De minimis emissions

- Non-required indirect emissions (employee travel, etc.)

- Energy efficiency project descriptions

- Offset projects

- Any additional information that might be helpful to participants, the public, or the Registry

Participants should note that while they are encouraged to report this optional information, none of the optional information will require certification. The Registry will be developing additional guidance on how this optional information should be reported.

Completing the Initial Registration Process
To complete the initial registration process, a participant must complete the relevant online web forms, assemble the required supporting information (See Section 4.4) to prove the reported information, and complete during the first year certification (See Section 5). After successfully completing the first year certification process, a participant's registration data will be formally entered into the Registry.

4.3 Annual Emissions Reporting

On an annual basis, the Registry expects participants will provide the following emissions reporting information using the Registry's web forms located on its web site.

Required Reporting
All participants' annual emission reports must contain the following information:

- Participant ID number and contact information

- All material direct and indirect emissions of CO_2 by source category consistent with a participant's defined organizational boundary and baseline

- *After three years of participation:* All material direct and indirect emissions of methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) by source category consistent with a participant's defined organizational boundary and baseline

- Total gross GHG emissions

- One or more GHG emission ratios that demonstrates emission efficiency

- Supporting documentation to certify the reported emissions (See Section 4.4)

- Classification of confidentiality

Optional Reporting
In addition to the required information, participants are also able, and encouraged to report additional information, such as:

- De minimis emissions
- Non-required indirect emissions (employee travel, etc.)
- Energy efficiency project descriptions
- Offset projects
- Any additional information that might be helpful to either the participant or the Registry

For annual reporting, as for baseline reporting, participants should note that while they are encouraged to report this optional information, none of the optional information will require certification.

To ease registering annual emissions for every year after their initial reporting year, participants will simply call up a copy of the previous year's emission sources by entering their entity ID number into the Application. If a participant's emission sources remain the same from year to year, it will only need to update the amount of fuel used each year. The Application will recalculate the corresponding GHG emissions, and the annual emissions report will be ready for submission to the Registry.

Designing the Application such that it will replicate the most recent emissions sources for future reports will eliminate the need for participants to re-enter data each year. If emission sources change from year to year, a participant will be able to easily adjust the default emission sources to reflect new activities.

4.4 Supporting Information

The Registry web forms will prompt participants to enter required data based on participants' emission sources. Therefore, specific supporting information will need to be supplied to the Registry. However, participants will also need to maintain a range of information at their offices to allow certifiers to confirm their initial registration, annual emission reports, and significant changes to their emissions.

At a minimum, participants should maintain the information listed below for their reported base year and annual emissions at their places of business. Additionally, copies of some of the supporting documentation will be provided to the Registry, depending on whether the Registry will be calculating the participants emissions or whether the participant calculates emissions. In the lists below, items denoted "RW" are to be submitted to the Registry by participants for whom the Registry calculates emissions. Items denoted "RC" are to be submitted to the Registry by participants who calculate emissions themselves. Items without any designation are to be maintained at the participant's offices.

Overall Supporting Documentation:
While most of a participant's explanations and comments about their emissions information will be recorded in the online forms, participants should make sure that they also have documentation of the following types of information at their places of business:

- RC - Description of the methodologies used to quantify emissions
- RC - Explanations for using emission factors other than the supplied default factors
- RC - Assumptions used in the emissions calculations
- RC, RW -Explanation of methodologies for identifying de minimis emissions
- RC, RW - Explanation of any significant emissions changes above the Change Threshold defined in section 4.1.2. Examples of causes for significant emissions changes may include:
    - Acquisitions
    - Mergers
    - Divestitures
    - Outsourcing (contracting activities previously conducted internally)
    - Insourcing (conducting activities that were previously contracted)
    - Shifting emissions to or from California
    - Changes in emissions estimation methodologies
- RC, RW - Source Category List by facility, updated annually

- Explanation of significant temporary emission changes that may fall below the Change Threshold, such as business cycle fluctuations, temporary process shut downs, etc.

Indirect Emission Reporting Documentation
Electricity, Steam, District Heating and District Cooling:

- RW - Energy bills for energy imported to all sites within a participant's boundary
- RW - Energy invoices for all energy exported from a participant's boundary

Direct Emission Reporting Documentation
Transportation:

- RW - Vehicle inventory (number of each type of vehicle, model, year, registration number, and location). Participants with fewer than 20 vehicles will complete their inventory online via the Registry database.
- RW, RC - Total fuel (any fuel type) consumed by each vehicle type OR total vehicle miles traveled by each vehicle type

On-site Combustion:

- Boiler, chiller, and co-generation engine inventory (number of each type of plant, permit number, size, description of use, and location)

- RW, RC - Fuel consumption for each type of plant

- RC - Emissions factors for fuel or process efficiency (if more specific than the Registry default factors)

Process:

- RW Details on specific process related emissions sources (necessary for Registry to calculate emissions)
- Parameters used to estimate emissions from each type of source

Fugitive:

- RW Details fugitive emissions sources (necessary for Registry to calculate emissions)
- Parameters used to estimate emissions from each type of source

4.5 Reporting Forms

The following sample forms are examples of the types of initial registration and annual reporting forms that participants will be required to submit to the Registry. Since reporting is expected to take place via the Registry's Application, the sample forms are only intended to help a potential participant better understand the Registry's requirements, and will not be used to register emissions. The web reporting forms will be easier to use than the sample forms, as entered data will trigger specific related detailed prompts, for example, if participants indicate that they import electricity, the next drop down box will prompt the participant to enter the total kWh per reporting year.

For those participants for which the Registry does not calculate emissions, additional reporting detail will be required. As described in Section 4.4, participants will need to provide information on the emission factors, calculation methodologies, and assumptions, as well as their annual source category list for each facility in addition to the information shown on these sample forms. Consistent with the approach or reporting emissions on a facility by facility basis, information in Sections 2 and 3 of the sample forms would be completed for each facility and submitted to the Registry.

Since the web forms are instantly customizable, they can be used to register California only emissions, US emissions, emissions based on management control, emissions based on management control and equity control, or any variation thereof.

The sample reporting forms are shown on the pages that follow:

California Climate Action Registry
Greenhouse Gas Emissions Report

Report for the Year _______

Submitted by

(Name of Reporting Organization)

____
Submission Date

Please check all that apply:
This report version is:

- ☐ Initial Registration
- ☐ Annual Report
- ☐ Baseline Adjustment
- ☐ Other Amendment/Correction

The report geographical boundary is:

- ☐ California only
- ☐ U.S. (Including California emissions)
  (Optional U.S. National reporting can only be submitted in conjunction with a separate report for California)

The organizational boundary is based on:

- ☐ Management Control
- ☐ Equity Share

Has your organization implemented any long-term shift of operations into or out of California during the past year?

- ☐ Yes
- ☐ No

SECTION I – Reporting Organization

1. Participant Information

Company Name:
Address:

Contact Person:
Title:
Address:
Tel:
Fax:
E-mail Address:

2. Participant Type

Select the category below that describes the participant:

☐ Corporation (Check all that Apply)
- ☐ Publicly Traded
- ☐ Privately held
- ☐ Non-profit
- ☐ Subsidiary (Identify parent: ____)

☐ Government (Indicate Level)
- ☐ Federal
- ☐ State
- ☐ Regional
- ☐ Local

☐ Joint Venture (List partners or attach list: ____________________________________)
☐ Limited Liability Company
☐ Other (Specify: ____)

3. NAICS Code

Record the primary two-digit or if possible up to six-digits of the North American Industrial Classification System (NAICS) code that best represents the reporting participant's primary activity:

NAICS code: ____ ____ ____ ____ ____ ____

For more information regarding the code most appropriate for the participant's representative code refer to the US Bureau of Census: http://www.census.gov/epcd/www/naics.html

Participant Business Activities
Please describe the company's primary activities and the type of GHG emissions that result from such activities:

Participant Information
Please list all subsidiaries of the company:

Number of facilities in CA:
Number of facilities in US:

Number of employees in CA:

Number of employees in US:

Annual revenue of total entity:

Year company was founded:

Do you have international operations?

Participant Environmental Information
Do you have a corporate environmental management system? Is it ISO 14000 certified?

Do you have a corporate system for tracking GHG emissions? Would you be interested in automating your annual Registry reporting?

Do you produce an annual environmental report

Do you participate in other GHG programs? Check all that apply:

- ☐ DOE 1605b
- ☐ Climate Leaders
- ☐ Climate Savers
- ☐ Other state registry?, please specify: _________________
- ☐ Other? please specify: _________________

Participant Boundaries?

4. Confidentiality

Check box if applicable:

☐ This report contains confidential information.

(If you are claiming confidentiality, include a letter explaining why the information would be likely to cause substantial competitive harm if publicly released.)

Attestation

I attest that the information reported on this form is accurate to the best of my knowledge and belief.

Attesting Official's Name:
Title:
Address:
Tel:

Date:

Section 2. Consolidated Results

Part A. Direct Emissions			
Greenhouse Gas	Emissions, tonnes	Global Warming Potential	CO2-Equivalent Emissions, tonnes
Carbon Dioxide		1	
Methane		21	
Nitrous Oxide		310	
Hydrofluorocarbons		multiple*	
Perfluorocarbons		multiple*	
Sulfur Hexafluoride		23,900	
Total CO2-Equivalent Direct Emissions			
Part B. Net Indirect Emissions			
Greenhouse Gas	Emissions, tonnes	Global Warming Potential	CO2-Equivalent Emissions, tonnes
Carbon Dioxide		1	
Methane		21	
Nitrous Oxide		310	
Total CO2-Equivalent Indirect Emissions			
Total CO2 Equivalent Emissions = Part A. + Part B.			
Note: emissions of GHGs other than carbon dioxide (shaded areas) are not required to be reported during the first 3 years of participation the Registry.			
*HFC and PFC GWPs vary by gas. Participants should apply the GWPs that apply to their specific emissions when calculating the			
CO2-eq emissions. The table below lists the global warming potential (GWP) of common HFCs and PFCs.			

Global Warming Potentials of HFCs and PFCs	
Gas	100-Year GWP
HFC-23	11,700
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF4	5,700
C2F6	11,900
C3F8	8,600
C4F10	8,600
C5F12	8,900
C6F14	9,000

Section 3a. Direct Emissions Results

Part A. On Site Fuel Combustion									
			Emissions, tonnes						
Fuel	Fuel Consumption	Specify Units	CO2	CH4	N20				
Natural Gas									
Petroleum Products									
Gasoline									
Distillate Oil									
Residual Oil									
Propane									
Butane									
Coal									
Waste									
Other – specify									
Total On Site Fuel Combustion Emissions									
Part B. Transportation Emissions									
			Emissions, tonnes						
Fuel	Fuel Consumption	Specify Units	CO2	CH4	N20				
Natural Gas									
Petroleum Products									
Gasoline									
Diesel Fuel									
Bunker Fuel									
Propane									
Butane									
Aviation Gasoline									
Jet Fuel									
Other – specify									
Total Transportation Emissions									

Part C. Process Emission								
			Emissions, tonnes					
Specify Types of Emissions*	Reporting Metric	Specify Units	CO2	CH4	N20	HFCs	PFCs	SF6
Total Process Emissions								
Part D. Fugitive Emissions								
			Emissions, tonnes					
Specify Types of Emissions*	Reporting Metric	Specify Units	CO2	CH4	N20	HFCs	PFCs	SF6
Total Fugitive Emissions								
Total Direct Emissions = Part A + Part B + Part C + Part D								
Note: emissions of GHGs other than carbon dioxide (shaded areas) are not required to be reported during the first 3 years of participation in the Registry.								
*For HFC or PFC emissions, use a separate line for each specific gas emitted, and identify the gas as part of the description.								

Section 3b. Indirect Emissions Results

Part A. Energy Imports									
			Imported Emissions, tonnes						
Type	Quantity of Energy Imported	Specify Units	CO2	CH4	N20				
Electricity									
Steam									
Heating									
Cooling									
Total Emissions from Energy Imports									
Part B. Energy Exports									
			Exported Emissions, tonnes						
Type	Quantity of Energy Exported	Specify Units	CO2	CH4	N20				
Electricity									
Steam									
Heating									
Cooling									
Total Emissions from Energy Exports									
Total Net Indirect Emissions = Part A. - Part B.									
Note: emissions of GHGs other than carbon dioxide (shaded areas) are not required to be reported during the first 3 years of participation in the Registry.									

Discussion

The following sections of the SB 527 legislation are applicable to the requirements of the information to be reported in the voluntary program:

SEC. 11. 42840(a) Participants shall utilize the following reporting procedures to establish a greenhouse gas emissions baseline, participants shall report their certified emissions for the most recent year for which they have complete energy use and fuel consumption data as specified in this chapter. Participants that have complete energy use or fuel consumption data for earlier years that can be certified may establish their baseline as any year beginning on or after January 1, 1990. After establishing baseline emissions, participants shall report their certified emissions results in each subsequent year in order to show changes in emissions levels with respect to their baseline year. Participants may report annual emission results without establishing an emissions baseline. Participants shall also report using industry-specific metrics once the registry adopts an industry-specific metric for the industry in question.

SEC. 11. 42840(b)(1) Participants shall report direct emissions and indirect emissions separately. Direct emissions are those emissions from applicable sources that are under management control of a participating entity, including onsite combustion, fugitive noncombustion emissions, and vehicles owned and operated by the participant. Indirect emissions that are required to be reported by participants are those emissions embodied in net electricity and steam imports, including offsite steam generation and district heating and cooling. Participants are encouraged, but are not required, to report other indirect emissions based on guidance that is adopted by the registry.

SEC. 11. 42840(b)(4) Participants shall not be required to report emissions of any greenhouse gas that is de minimis in quantity, when summed up across all applicable sources of the participating entity.

SEC. 11. 42840(c)(1) All participants shall report direct and indirect carbon dioxide (CO2) emissions that are material to their operations.

(2) The registry shall also encourage participants to monitor and report emissions of the following gases:(A) Hydrofluorocarbons (HFCs),(B) Methane (CH4),(C) Oxides of nitrogen (N2O),(D) Perfluorocarbons (PFCs),(E) Sulfur hexafluoride (SF6).

(3) The report of information specified in paragraph (2) is optional for three years after a participant joins the registry. After participating in the registry for a total of three years, participants shall report emissions required by both paragraphs (1) and (2).

(4) Emissions of all gases under this subdivision shall be reported in mass units.

The reporting guidelines described above are in accordance with the reporting requirements of SB 527. The forms and description of information to be reported to the Registry and maintained by the participants were developed based on the collective review of the WRI/WBCSD protocol (WRI/WBCSD, 2001), the Australia Greenhouse Challenge program (AGO, 1999), the UK Emissions Trading program (DEFRA, 2001a; 2001b), the U.S. DOE 1605b voluntary program (EIA, 1994; 2001), and Canada’s Climate Change Voluntary Challenge program (VCR, 1999).

5.0 Certification

Senate Bill 527 requires that participants registering baseline emissions and emissions results in the Registry provide certification of their methodologies and the results. Therefore the Registry will require that emissions data submitted to it be certified. This aspect of the Registry program is key to achieving its stated purpose of enabling the state to support the consideration of registered emissions results in any future international, national, or state regulatory scheme. It is also important for the participants to know that their data have been certified by an independent, third party certifier.
Alternative methods of certification are encouraged by SB 527. It is expected that different companies will have different goals and objectives in participating in the Registry. Among these may be simply learning about their operations and gaining practice in conducting exercises involved in estimating greenhouse gas emissions, using the data obtained in promotional activities, and ensuring credit for any greenhouse gas emissions reductions achieved prior to any regulatory regime. Although participants may enter the Registry with these different objectives in mind, since all data must be certified, it all must meet a certain minimum quality standard. Certification is the method by which the data are ensured to be of a high enough quality, meaning complete, consistent, accurate, and transparent, to warrant the state providing its best efforts to support them.

5.1 Independent Certification Principles

The purpose of certification is to provide an independent review of data and information being submitted to the Registry to ensure that they meet certain quality criteria. The independent certification process maintains the criteria of completeness, consistency, accuracy, and transparency as its underlying principles.

Completeness. One purpose of certification is to ensure accounting of all material greenhouse gas emissions sources and activities within the specified scope of the participant's inventory. Ensuring that baseline and annual emissions results include all sources that are not de minimis in quantity and that proper accounting for vertical integration is conducted are included as part of the certification process.

Consistency. Reporting by participants must allow meaningful comparison of emissions performance over time. Independent certification, therefore, ensures that consistent methodologies and measurements are used between the baseline results and annual emissions results. Changes to the baseline are reviewed as part of certification and are noted by the certifier to ensure appropriate comparisons.

Accuracy. The basis of certification is to ensure that all reported data are within the materiality threshold of the actual values. Independent certification ensures that calculations and estimations are as accurate and as precise as necessary to prevent material errors.

Transparency. Certification does not only provide an additional check on the transparency involved in reporting greenhouse gas emissions, it also is a transparent exercise itself. Certification activities are clearly and thoroughly documented to provide the ability for outside reviews to be undertaken, if desired by the Registry.

5.2 Independent Certification Process

The certification process outlined below represents a comprehensive approach, which the Registry may require of some participants. Within the realm of independent certification, however, there is a range of options of conducting certification. The reason for this range is that different participants will have different situations, including number of sites, sizes of sites, geographic distribution, extent of operation, and types of emissions.
Where required by the Registry, the independent certification process consists of five steps: 1) understanding management systems, 2) assessing strengths and weaknesses of management systems, 3) reviewing emissions data, 4) evaluating certification findings, and 5) reporting certification findings.

Understanding management systems. The first step in certification is to review and understand the management systems in place for estimating and reporting greenhouse gas emissions. This provides the certifier with the necessary basis for evaluating the processes and programs the participant has in place as part of their participation in the Registry.

Assessing strengths and weaknesses of management systems. Once the certifier understands the management systems in place, those programs and processes can be evaluated to assess the relative risks associated with each aspect of the participant's estimation and reporting of greenhouse gas emissions. If a participant has strong management systems in place to handle estimation and reporting of a small emissions source, that source would be assigned a relatively low risk weighting. On the other hand, if the participant has weak management systems in place to handle a large source, that source would be assigned a relatively high risk weighting.

Reviewing emissions data. Certification is a sampling exercise. SB 527 specifies that sampling will be utilized as part of the certification procedure. As a result, it is not expected that a certifier will review all documents and recheck all calculations. Rather, the process includes evaluating which areas are of greatest concern and checking those more thoroughly than other areas that are of lesser concern to the certifying organization. The risk weightings assigned in the previous step are used to ensure that an appropriate amount of effort is provided in sampling the data. This step is the one that requires the most effort and is the one that yields the most information on the quality of the data reported. It includes reviewing the emissions inventory as well as each type of emission source (stationary combustion, transportation, indirect, process, and fugitive).

Evaluating certification findings. Once the data are reviewed, the findings from that review are evaluated to determine the overall quality of the data.

Reporting certification findings. The final step is issuing the certification report to the appropriate body within the participant's organization. In most cases this will be the board of directors or other management entity. As part of this report, the certifier will issue a statement regarding the quality of the data.

5.2.1 Small size with simple operations

The simplest certification process would be for a participant with only one site and only indirect emissions (electricity, district heating or cooling) and emissions from natural gas supplied by a utility. Such a participant would require a site visit only if deemed necessary by the certifier, with subsequent visits recommended if any characteristics of the participant changed (e.g., new sites, changed location, begin new operations, etc.). The certifier may interview the participant by telephone to receive answers to questions he or she might have about information submitted to the Registry and to determine the need for a site visit. The site visit would be used to ensure that all material greenhouse gas emissions sources have been included and appropriately accounted for, and to gain a better understanding of the participant's operations and characteristics. The certifier would then review any processes in place for greenhouse gas emissions reporting and any utility bills or other data and documentation used to calculate emissions. The data review can be completed away from the participant's site. Possible locations for the data review include the certifier's office or possibly the Registry itself. Once the certifier is satisfied that the participant's only emissions are the result of purchased utilities, the only data that would need to be reviewed would be the utility bills and associated documentation.

5.2.2 Medium size with simple operations

For larger participants and those with more than one site, certification would take a slightly different approach. This process would be similar to the previous example, except that an initial site visit would be required. Site visits in subsequent years would be conducted at the discretion of the certifier.

5.2.3 Large size with complex operations

For a participant of large size with complex operations, a more complex certification process is necessary. A first time site visit would be required, as would subsequent site visits every three years in order to ensure that all material greenhouse gas emissions sources have been accounted for appropriately and to review any changes that may have occurred during the previous years. In addition, the certification process for the third year would be more in depth than the others and would review data from the intervening years. A management system review would also be conducted. Sampling techniques would be utilized to review data based on priorities assigned during the management system review, with aspects having higher risk getting more attention. If the participant has multiple sites, not all sites will be required to be visited, although multiple sites may be visited by the certifier based on sampling techniques.

The three examples above do not represent all possible instances of independent certification. Specific certification processes will be utilized by certifiers based on the

Registry's certification protocol and the specific characteristics of the participant to be certified. Although the certification protocol will be comprehensive in its reviews of potential emissions sources, not all parts of it will apply to all participants. Any aspects of the certification protocol that do not apply to a certain participant will not be completed at the discretion of the certifier.

5.3 Record Keeping and Retention

Regardless of which certification option a participant may be subject to, there are certain record keeping and retention policies that should be followed. Aside from being impractical for the Registry to maintain all the necessary records for each participant, not all participants will be submitting sufficient data from which to certify emissions results. Each participant should maintain any relevant records from which emissions results have been calculated. Such records may include, but not be limited to, utility bills, fuel consumption records, emissions data, process data and schedules, and past reports. Although it is not possible to predict what any future regulatory regime may require regarding record keeping and retention, it is impractical to require participants to retain records indefinitely. It is, however, inadvisable for participants to destroy or dispose of relevant records immediately after filing emissions reports. This would hinder any future certification or review activities, putting the participant at a disadvantage in case of regulatory intervention. In addition, baseline inventory data is key to determining temporal trends in greenhouse gas emissions. While it is impractical to require participants to retain records indefinitely, it is advised that participants evaluate retention periods to ensure adequate data availability for future reviews.

Discussion

SB 527 contains a large number of sections that relate to certification:

> SEC. 4.
>
> (e) The state hereby commits to use its best efforts to ensure that organizations that establish greenhouse gas emissions baselines and register emissions results that are certified in accordance with this chapter receive appropriate consideration under any future international, federal, or state regulatory scheme relating to greenhouse gas emissions. The state cannot guarantee that any regulatory regime relating to greenhouse gas emissions will recognize the baselines and annual results recorded in the registry.
>
> SEC. 5.
>
> (c) "Certification" means the determination of whether a given participant's greenhouse gas emissions inventory (either baseline or annual result) has met a minimum quality standard and complied with an appropriate set of registry-approved procedures and protocols for submitting emissions inventory information. The process for certification of emissions results will be specified within the procedures and protocols approved for industry-specific emissions inventory reporting, and may involve a range of options depending upon the nature of the emissions, complexity of a company's facilities and operations, or both, and the procedures deemed necessary by the registry board to validate a participant's emissions information.

SEC. 6. The purposes of the California Climate Action Registry shall be to do all of the following:

(c) Enable participating entities to voluntarily record greenhouse gas emissions made after 1990 in a consistent format that is certified.

(d) Ensure that sources in the state receive appropriate consideration for certified emissions results under any future federal regulatory regime relating to greenhouse gas emissions.

SEC. 8.

(a) The procedures and protocols for monitoring, estimating, calculating, reporting, and certifying greenhouse gas emissions established by, or approved pursuant to, this chapter shall be the only procedures and protocols recognized by the state for the purposes of the registry, as described in Section 42810. These procedures shall be, to the extent practicable, consistent with the methods and practices used for the statewide inventory of greenhouse gas emissions prepared by the State Energy Resources Conservation and Development Commission, as required by Section 25730 of the Public Resources Code.

SEC. 9. The registry shall perform all of the following functions:

(c) Adopt procedures and protocols for certification of reported baseline emissions and emissions results. When adopting procedures and protocols for the certification, the registry shall consider the availability and suitability of simplified techniques and tools.

(f) Maintain a record of all certified greenhouse gas emissions baselines and emissions results. Separate records shall be kept for direct and indirect emissions results. The public shall have access to this record, except for any portions of a participant's emissions results that a participant may deem confidential.

SEC. 13.

(a) Participants registering baseline emissions and emissions results in the registry shall provide certification of their methodologies and results. The registry board may, upon recommendation of the State Energy Resources Conservation and Development Commission and the state board, following a public process, adopt simplified procedures to certify emissions results as appropriate. Participants shall follow registry-approved procedures and protocols in determining emissions, and supply the quantity and quality of information necessary to allow an independent ex post certification of the emissions baseline and emissions results reported under this program.

(b) The registry shall adopt a list of approved third-party organizations recognized as competent to certify emissions results as provided in this chapter. The process for evaluating and approving these organizations shall be developed in coordination with the State Energy Resources Conservation and Development Commission. The registry may reopen the qualification process periodically in order for new organizations to be added to the approved list.

(c) As appropriate, the registry shall refer participants to the organization on the approved list described in subdivision (b).

(d) Where required by the registry for certification, organizations approved pursuant to subdivision (b) shall do all of the following:

(1) Evaluate whether the participant has a program, consistent with registry-approved procedures and protocols, in place for preparation and submittal of the information reported under this chapter.

(2) Check, during certification, the reasonableness of the emissions information being reported for a random sample of estimates or calculations.

(3) Summarize its review in a report to the board of directors, or equivalent governing body, of the participating entity, attesting to the existence of a program that is consistent with registry-approved procedures and protocols and the reasonableness of the reported emissions results and noting any exceptions, omissions, limitations, or other qualifications to their representations.

(e) In conducting certification for a participant under this program, the approved organization shall schedule any meeting or meetings with the participant in advance at one or more representative locations and allow the participant to control property access. The meetings shall be conducted in accordance with a protocol that is agreed upon in advance by the participant and the approved organization. The approved organization shall not perform facility inspection, direct measurement, monitoring, or testing unless authorized by the participant.

(f) To ensure the integrity and constant improvement of the registry program, the State Energy Resources Conservation and Development Commission shall perform on a random basis an occasional review and evaluation of participants' emissions reporting, certifications, and the reasonableness of the emissions information being reported for analysis of estimates or calculations. The commission shall report any findings in writing to the registry. The registry shall include a summary of these findings in the biennial report to the Governor and the Legislature required by Article 5 (commencing with Section 42860).

SB 527 makes extensive mention of certification. It directs the Registry to consider simplified certification techniques. It does not, however, suggest what these simplified techniques might entail.

Certification, in general, refers to a spectrum of approaches, ranging from minimal effort to an exhaustive review of all calculations and assumptions. At one end of the spectrum is the approach that very minimal data evaluation need occur, so any results can be reported and assumed to be correct. This extreme is not desirable because it does not provide enough assurance about accuracy or validity. The approach at the other extreme, however, is also undesirable. The other end of the spectrum is conducting an exhaustive review of everything, including visiting all operational sites, checking all calculations and assumptions used, interviewing all personnel involved in reporting, inspecting and calibrating all monitoring and measurement equipment, and closely reviewing any outside energy providers (e.g. utilities). Such a review would be prohibitively expensive and would require more time and effort than could be provided. What follows is a description of different options from the center of the certification spectrum. It is believed that these options provide better insight into certification than the extreme examples above.

Based on the range of possible objectives companies may have when participating in the Registry and the different certification necessities, there are two main options:

- Self Attestation
- Independent Certification

The level of rigor with which emissions results are reviewed varies from minimal to significant, and each option has its own benefits and drawbacks as discussed and presented below.

Self Attestation

For self attestation, the participant would sign the results asserting to the validity of the information submitted to the Registry. The benefit from this type of certification is that the participant would be able to participate in the Registry and obtain recognition for it. This option is also the less expensive of the two, since all that is required is for the reporter to attest to its validity. The primary drawback is that, because the results are not independently certified, the state would not be able to use its best efforts to ensure that the participant receives appropriate consideration under a future regulatory scheme relating to greenhouse gas emissions.

For self attestation, the participant may have internal reviewers evaluate the inventory data submitted to the state following the accepted certification protocol and confirm the accuracy of the information. The benefits from this certification are that a participant would be able to participate in the Registry and obtain recognition for it, and learn from the process. The internal reviewing group would be able to provide the organization with suggestions for improving upon the data gathering systems or estimates used. This would help them prepare for third party certification. The costs for such a review would vary based on the participant's operations and complexity, but would be minimal to moderate.

Independent Certification

Independent certification is the more rigorous of the two options and includes a more in depth review of greenhouse gas emissions programs and results than the other options. Although this is the case, the independent certification process is not meant to be onerous or excessive. Because of the need to certify that all appropriate and material greenhouse gas sources have been included in the inventory, site visits may be required. Site visits to all facilities of a company are not, however, required. The process is anticipated to include a visit to a participant's corporate headquarters or other central location. The certifier can then meet with the people responsible for compiling emissions results from the other sites and can devise a plan to conduct telephone interviews with a sample of sites and visit a smaller sample of operational sites. Smaller participants, however, may only require minimal effort to conduct independent certification. For these entities, a short site visit, perhaps as little as one hour, will be needed to verify sources, followed by verifying the data and assumptions used in calculating emissions. The range of effort required for independent certification is anticipated, therefore, to be from one day, including a one-hour site visit, to ten person days for the largest participants.

Although self attestation certification has minimal costs and is, therefore, attractive to participants, it does not fulfill statutory requirement of independent certification by an approved third party certifying organization. In addition, such a minimal review of processes and data submitted to the Registry would not provide assurances of the data's quality and would not permit the state to use its best efforts to support such data. This is one of the prime purposes of the Registry, which would be negated if such a certification process were adopted. The participants would not benefit from baseline protection, the Registry would not be able to accept the data, and the State would not be able to support the data. Given those concerns, independent certification is recommended as the certification method for Registry participants.

The cost for independent certification will also vary significantly, based on level of effort required and the rates for individual certifiers. It is anticipated, though, to range from less than $750 for small operations (if a site visit is required) to over $15,000 for the largest. Independent certification will be based on the protocol accepted by the Registry. The protocol will include systematic directions for conducting certification activities, although not all of the protocol will be applicable to all operations and participants. Consequently, the protocol is a guideline to be followed by certifiers, but does not take the place of professional judgment on the part of the certifier.

Within independent certification there are different options for how the certification is conducted, depending upon the size and complexity of a participant. The prime differences between the options are the requirement or recommendation for a site visit and the frequency of such site visits. For the smallest participants, site visits are not required, but may be requested by the certifier. The certifier may request a site visit if, for example, there are inconsistencies in the information submitted to the Registry or if telephone conversations with the participant lead the certifier to question the completeness of the submitted information. Following certification in the first year, subsequent site visits are recommended only if the characteristics of the participant have changed in the interim. Absent any changes, the certifier may simply need to conduct checks on a sample of the data being reported and review any relevant management systems to ensure that they have not changed either. The benefit of not conducting site visits and in depth reviews every year is that the expenses associated with certification are reduced. This is meant to encourage participation and reduce the burden on the smallest participants.

For large, complex participants, however, more in depth reviews are necessary to ensure that greenhouse gas emissions data are complete, consistent, accurate, and transparent. A site visit is required in the first year to ensure that all appropriate emissions sources have been accounted and to gain a better understanding of the participant's operations. The certification process in that first year will also be more extensive to review management systems and a sample of reported data. If a participant has multiple sites, a sample of those sites may be visited at the discretion of the certifier. In subsequent years, site visits will be required every third year and for any year in which a material change in operations or management systems occurred. The certification process for the third year reviews will be similar to the first year review and will also include a review of the previous two years' data. During the intervening years, the certifier will review the data being reported, but that data will not be considered fully certified until the third year review. The purpose for spacing out the in depth reviews is, again, economic. By only conducting the most rigorous reviews every three years and for years in which changes have occurred, the costs to the participants will be reduced.

Reviews for medium sized operations will be a balance of those for small and large participants. For these participants, an initial site visit will be required, but subsequent visits will be conducted at the discretion of the certifier.

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Appendix: A. Boundaries and Reporting Comparison Table

Table A1. GHG Reporting, in California, U.S., and International Programs

	Specific Programs		
Protocol Elements	SB 527 Legislation ***Referenced Document:*** Senate Bill SB 527, October 13, 2001 http://www.energy.ca.gov/global_climate_change/documents/2001-11-30_SB_527.PDF	DOE 1605b ***Referenced Documents:*** [5] *Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, General Guidelines, US DOE, Washington, DC, October 1994.* http://www.eia.doe.gov/oiaf/1605/1605b.html [6] Instructions for Form EIA-1605 Voluntary Reporting of Greenhouse Gases For Data Through 2000, US DOE, Washington, DC, Feb. 2001. http://www.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/1605INST00.pdf [7] Recording Transfers and Retirement of Greenhouse Gas Reductions in the Voluntary Reporting Program, unpublished white paper. http://www.eia.doe.gov/oiaf/1605/trade.html	WRI/ WBCSD Protocol ***Referenced Document:*** "The Greenhouse Gas Protocol: a corporate accounting and reporting standard", World Business Council for Sustainable Development, World Resources Institute, Washington DC, October, 2001. http://www.ghgprotocol.org/standard/ghg.pdf
1. Boundary Determinations in terms of ownership vs. management control and definitions of management control, legal ownership and equity share	The basic unit of participation is an entity in its entirety, such as a corporation or other legally constituted body, any city or county, and each state government agency. The registry shall not record emissions baselines and reductions for individual facilities or projects, except to the extent they are included in an entity's emissions reporting. [Sec. 11. (d), p. 15] Notes: "Management control", "legal ownership", and "equity share" are not defined by SB 527.	The program is a registry of claims of emission reductions, rather than an indication of legal ownership. The program database contains several instances where more than one party has claimed the same emission reduction. Thus the EIA can provide no assurance that an entity wishing to transfer or acquire the rights to reductions reported under the program actually "owns" the reductions that are being transferred. [7][p.1] For project-level reporting, you can report emissions, emission reductions, or sequestration achieved after the baseline period as a result of one or more individual activities. Participants are encouraged to aggregate similar actions with similar effects into a single project. The project boundary should encompass all the significant and quantifiable effects of the project. For Entity-level reporting you can report emissions, emission reductions, and increases in sequestration for your entire entity achieved after the baseline period (1987 through 1990) on an annual basis through any measure. [6][p.3,5]	Boundary determinations can be based on management control and equity share: Boundaries based on management control are to report 100% of their emissions for controlled entities, and equity share for jointly controlled entities. Boundary based on equity share, are pro rated based on the equity share of controlled and significant influence entities, zero emissions are reported otherwise. Management Control: the ability of a company to direct the operating policies of another entity/facility. If the company owns more than 50 percent of voting interests, this implies control. Significant influence: a company exerts significant influence if the company owns voting interests of between 20 and 50 percent. Equity share is defined as the percentage of economic interest in/benefit derived from an operation. [Ch. 3, p.15] Notes: "legal ownership" is not defined in WBCSD protocol.

Table A1. GHG Reporting, in California, U.S., and International Programs (continued)

Protocol Elements	SB 527 Legislation	DOE 1605b	WRI WBCSD Protocol
2.Boundary determinations with equity changes over time with mergers, acquisitions and divestitures and vertical integration.	[Sec. 11. (d) (5), p. 15] To prevent changes in vertical integration within corporations from leading to apparent emissions reductions when in fact no reductions have occurred, the registry must treat mergers, acquisitions, and divestitures as follows: (A) The emissions baselines of any merged or acquired entity shall be added together, and the registry will treat the resulting entity as if it had been one corporation. (B) In divestitures, the emissions baselines of the affected corporations will be split. If the divested corporation is purchased by another firm, the registry will treat that purchase as a merger with the purchasing corporation. If the divested corporation remains a separate entity after the divestiture, its registry baseline shall reflect the emissions associated with the entity's operation before divestiture among the divesting and the divested entities, and the registry shall adjust their baselines accordingly. • Any adjustments for changes in vertical integration shall be verified in the annual emissions certifications.	In this program three types of transactions are described for project-level and entity-level reporting: 1. Transfer from another party to a reporting party of a claimed reduction ("a purchase") 2. Transfer of a claimed reduction by a reporting party to another party ("a sale"). 3. Reporting party's refrain from exercising any rights or privileges that may be associated with a report of emissions reductions ("a retirement") Project reduction acquisitions "a purchase": A new project is created for recording the new ownership of a project reduction and record the source that they acquired. Project reduction transfers "a sale": A "sale" of a reduction should be recorded as a negative number. The transferring party should continue to record the full amount of the project reductions. The negative number acts as an offset to the reported reduction. When all reductions associated with a project are summed, the total number of tones reported by the selling company will be reduced by the amount transferred. Project retirement reductions: A retirement is similar to a transfer to "nobody" and recorded as a negative number. The retiring party should continue to record the full amount of the project reductions. The negative number acts as an offset to the reported reduction. When all reductions associated with a project are summed, the total number of tones reported by the selling company will be reduced by the amount transferred. [5][p. 1-4]	Boundary determinations with equity changes over time are adjusted. [Ch. 3, p. 15] Changes over time are also reflected in the base year adjustment policy, with the basis for making any adjustments and any 'significant threshold' applied clearly articulated by the participant. The following rules should be observed for base year emissions adjustments: • The base year emissions should be adjusted if significant structural changes occur in the organization. Significant structural change depends on the size of the organization. Examples include mergers, major acquisitions, and divestitures. • The base year emissions should be adjusted to account for the transfer of ownership/control. • The base year emissions should not be adjusted for organic growth or decline. • The base year emissions should not be adjusted for any changes in outsourcing/insourcing activities if the company is reporting its indirect emissions from such activities under scopes 2 or 3. • If significant structural changes occur during the middle of a year, the base year emissions should be adjusted on a pro-rata basis. [Ch. 6, p. 31]

Table A1. GHG Reporting, in California, U.S., and International Programs (continued)

Protocol Elements	SB 527 Legislation	DOE 1605b	WRI WBCSD Protocol
3. Reporting emissions from joint ownership, subsidiaries	In cases of joint ownership, emissions are reported by the managing entity, unless the owners decide to report emission on a pro rata basis. [Sec. 11. (b) (3), p. 14] Participants may report emissions baselines and annual emission results from subsidiaries if the parent corporation is clearly defined. [Sec. 11. (d) (1), p. 15] Notes: "Pro rata basis" is not defined in SB 527.	Joint Ownership of emission sources – If an emissions source is only partially owned by your entity, the emissions from the source should be allocated to the direct and indirect categories based on your entity's ownership share. For example, if your entity owns ten percent of the source, then ten percent of the emissions from the source should be allocated to the direct category, and the remaining 90 percent should be treated as indirect emissions. Allocation of emission between direct and indirect should always be based on ownership unless the owners have agreed to divide the greenhouse gas emissions among themselves according to some other scheme. Such agreements take precedence for the purposes of allocating emissions between the direct and indirect categories. [6][p. 4,5] Under the 1605b program a participant may report on an emission reduction or carbon sequestration project undertaken in association with others, provided that the other potential reporters are identified. Agreements can be made with other parties to report all or part of the emission reductions or sequestration achieved. [6][p. 3]	Reporting of emissions for entities involving joint ownership would be based on equity share for controlled and significant influence entities, and zero otherwise. [Ch. 3, p. 15] GHG emissions from entities/facilities that are not under significant influence or control (e.g. the company owns less than 20% of the voting interests) are generally not reported. This is consistent with financial accounting standards where a company would only recognize revenue if dividends were paid or a loss. [Ch. 3, p. 15] Notes: No specific discussion of subsidiaries regarding reporting, but assumed that it follows same reporting criteria as ownership and management control schemes and that boundaries based on subsidiary status are clearly defined in the reporting of emissions. [Ch. 10, p.50, #2]
4. Determine the level of reporting detail whether at source, project or facility level.	The basic unit of participation is an entity in its entirety, such as a corporation or other legally constituted body, any city or county, and each state government agency. The registry shall not record emissions baselines and reductions for individual facilities or projects, except to the extent they are included in an entity's emissions reporting. [Sec. 11. (d), p. 15] Participants shall not be required to report emissions of any greenhouse gas that is de minimis in quantity, when summed up across all applicable sources of the participating entity. [Sec. 11. (b) (4), p. 14]	For this voluntary reporting scheme, reporting can occur at two levels: 1. When reporting at the entity level, a participant should provide a comprehensive estimate of the emissions, emissions reductions, and increases in sequestration that occur as a result of entity's activities. 2. When reporting at the project level, the participant should report only emissions, reductions, and sequestration associated with the project. In general the participant is not expected to collect extensive new data. Use of standard coefficients to convert fuel consumption and energy consumption to emissions are encouraged. [6][p. 4]	The level of reporting detail depends on the characteristics of the company, the intended purpose of the GHG information, and the needs of the users. When choosing such boundaries, the protocol recommends considering the following dimensions: 1. organizational structures: operating licenses, ownership, legal agreements, joint ventures, etc. 2. the business context: nature of activities, geographic locations, industry sector(s), purpose of information, users of information 3. specific exclusions or inclusions and their validity and transparency The boundaries should represent the substance and economic reality of the business, and not merely its legal form. [Ch. 1,p. 8]

Table A1. GHG Reporting, in California, U.S., and International Programs (continued)

Protocol Elements	SB 527 Legislation	DOE 1605b	WRI WBCSD Protocol
5. Determine additional information necessary and level of detail such as geographical distribution; CA, US, worldwide	In addition to the chemical or physical identity of the pollutants included, the inventory must also include the following: (A) The geographical area covered. (B) The institutional entities covered. (C) The time period over which emissions are estimated. (D) The types of activities that cause emissions. [Sec. 5. (f) (1), p. 9] The emissions inventory will also include sufficient documentation and supporting data to make transparent the underlying assumptions and calculations for all of the reported results [Sec. 5. (f) (2), p. 9] Participants are encouraged to report all of their GHG in the US. The registry will review in three years possibility of mandatory reporting. [Sec. 11. (d) (3), p. 15]	Additional information for reporting: A. Entity identification (for both project and entity – level reporting) [6][p. 11]: B. For project-level reporting: Part I. General project information. Part II. Specific Project Information. Part III. Greenhouse gas Emissions and Reductions: Emissions, emission reductions and sequestration of direct and indirect emissions, the gas, unit of measure, quantity, accuracy, and future reduction estimates. Part IV. Project evaluation: Reference case, reports to other agencies, multiple reporting of same project, estimation methods. [6][p. 13-34] C. For entity-level reporting: Part I Direct emissions and reductions in direct emissions. Part II Indirect emissions and reduction in indirect emissions for power transactions. Part III. Sinks and sequestration.. Part IV. Total Emissions and reductions. Part V. Additional information: estimation methods used, scope of entity level reporting, any supplemental information: e.g. year-to-year changes in emissions and reductions due to weather, production levels, outsourcing, closing of plants, and changes in O&M procedures. [6][p. 35-39] D. Commitments to reduce GHGs: Part I. Entity commitments. Part II. Financial commitments. Part III. Projects to reduce GHGs. [6][p. 41-43] The general geographical boundary for reporting is within the US. Achievements from foreign activities outside the US, its territories and trusts are considered foreign activities and should be reported separately from domestic activities. [6][p. 3]	• outline of the organization/reporting boundaries, the reporting period covered, justify exclusions. • report control & equity share-based approaches • report emissions data separately for each scope • report emissions data for all six Kyoto Protocol GHGs in metric tonnes and metric tonnes CO2-e • illustrate performance over time • describe calculation methodologies used to calculate emissions, or reference to the tools used. • provide context for significant emissions changes, e.g. extended process shut downs, acquisitions/divestitures, process changes, or changes in calculation methodologies • report any emissions reduction credits that are banked, purchased from, or sold to a third party. • report emissions sequestered • report emissions attributable to the generation of exported electricity and steam (by a non-electric utility) • provide a contact person The following are optional: • subdivide emissions for transparency • report ratio performance indicators • illustrate performance against internal and external benchmarks • outline any GHG management/reduction programs outside the reporting boundaries. • report emissions of GHGs not covered by Kyoto • outline external assurance of emissions data [Ch. 9, p. 45]

Table A1. GHG Reporting, in California, U.S., and International Programs (continued)

Protocol Elements	SB 527 Legislation	DOE 1605b	WRI WBCSD Protocol
6. Describe the issues surrounding direct and indirect emissions	Direct emissions are those emissions under management control of a participating entity. Indirect emissions are those emissions embodied in net electricity and steam imports, including offsite steam generation and district heating and cooling. Participants are encouraged, but are not required, to report other indirect emissions [Sec. 11. (b) (1), p. 13] After January 1, 2004, the registry board, in coordination with the SERCDC, may revise the scope of indirect emission source types that are required to be reported. [Sec. 11. (b) (2), p. 13]	In general for both project-level reporting and entity-level reporting, emissions from sources owned by the entity should be allocated to the direct and indirect categories based on the entity's ownership share. For example, if your entity owns ten percent of the source, then ten percent of the emissions form the source should be allocated to the direct category, and the remaining 90 percent should be treated as indirect emissions. Allocation of emission between direct and indirect should always be based on ownership unless the owners have agreed to divide the greenhouse gas emissions among themselves according to some other scheme. Such agreements take precedence for the purposes of allocating emissions between the direct and indirect categories. [6][p. 4,5] For project-level reporting, direct and indirect emissions should be reported. Direct emissions are emissions owned (wholly or in part) or leased by the entity. Indirect emissions are emissions from sources outside the entity that are affected by the entity's activities, e.g. the emissions of an electric utility resulting from the entity's electricity consumption. [6][p. 15] For entity-level reporting, both direct and indirect emissions are to be reported. Direct emission sources include emissions from: • Stationary combustion – this includes emissions resulting from the combustion of fuel at stationary sources owned (wholly or in part) or leased. • Transportation – this includes emissions resulting from the combustion of fuel by mobile sources owned (wholly or in part) or leased by the entity. (this includes emissions from non-transportation mobile equipment such as construction, mining and farm equipment.) Other direct sources – this includes emissions from processes such as methane emissions from coal mines, oil and natural gas systems and landfills; and nitrous oxide from adipic acid production. [6][p. 35-36]	*Companies should report GHG emissions from scopes 1 and 2. Companies are encouraged to report scope 3 emissions.* Scope 1: Direct GHGs are emissions from sources that are owned or controlled by the reporting company. [Ch. 4, p. 21] Scope 2: GHG emissions from imports of electricity, heat, or steam. Emissions attributable to exported/sold electricity, heat, or steam should be reported as scope 1 emissions. [Ch. 4, p. 21] Scope 3: Other indirect GHG emissions that are a consequence of the activities of the reporting company, but occur from sources owned or controlled by another company, [Ch. 4, p. 21]

Table A1. GHG Reporting, in California, U.S., and International Programs (continued)

Protocol Elements	SB 527 Legislation	DOE 1605b	WRI WBCSD Protocol
7. Outsourcing, subcontracting and changes to baselines	Participants that outsource production services must report emissions associated with the outsourced activity and remove these emissions from their emissions baseline. The subcontracted entity, if it voluntarily chooses to participate in the registry shall report emissions associated with the outsourced activities it has taken over. Participants will attest at least once each year that the entity has not outsourced any emissions, or that if it has, that all emissions subtracted from the entity's baseline emissions. [Sec. 11. (d) (4), p. 15]	Emissions due to outsourced activities are reported as supplemental information at the entity level. [5][p. 39]	A comprehensive identification of indirect emissions sources also includes accounting for GHGs associated with 'outsourcing/contract manufacturing' or franchises, e.g. drilling operations, building construction, facilities management, printing, waste management, retail outlets, etc. [Ch. 7, p.35] There should be no adjustment to the base year for the outsourcing of operations that came into existence after the base year was set. The same rule applies to insourcing. [Ch. 6, p.33] The base year emissions should not be adjusted for any changes in outsourcing activities if the company is reporting its indirect emissions from such activities under scopes 2 or 3. The same rule applies to insourcing. [Ch. 6, p.31]
8. Reporting procedures for participants that choose to report greenhouse emissions on a statewide basis need to show: A) Changes in a participant's operations that result in a long-term shift from CA to other states. B) Corresponding change in the participant's baseline	If a participant changes from statewide to national reporting under this program, changes to its baseline will be treated in a similar manner as changes in vertical integration. [Sec. 11. (d) (6), p. 16] To ensure that reported emissions accurately reflect shifts in operations to or from other states, the registry must adopt, in consultation with the CEC, at a public meeting and following at least one public workshop, reporting procedures for participants that choose to report greenhouse emissions on a statewide basis that require participants to show both of the following: (A) Changes in a participant's operations, such as a facility startup or shutdown, that result in a significant and long-term shift of greenhouse gas emissions from California to other states or from other states to California. (B) The corresponding change in the participant's baseline. [Sec. 11. (d) (7), p. 16]	The 1605b voluntary program is a national US reporting program. Participants are allowed to report emissions, emissions reduction and sequestration projects and entity activities outside the US. However, achievements from foreign activities outside the US, its territories and trusts are considered foreign activities and should be reported separately from domestic activities. [6][p. 3]	There is no reference to changes in reporting based on location changes. Organizational boundaries, as described in item 1 above, are based on management control and equity share. Under these criteria of boundary definition, political/geographical boundaries are relevant to distinguishable organizational boundaries. In this protocol it is the discretion of the participant to determine spatially related boundaries. If the boundary of reporting changes relative to the base year boundary, then the base year is changed in accordance to new boundary. [Ch3. P. 15] & [Ch. 6, p. 31].

Table A2. GHG Reporting Programs in Other Countries

	Specific Programs		
Protocol Elements	UK Emissions Trading Program ***Referenced Documents:*** [3] Draft Framework Document for the UK Emissions Trading Scheme, Department for Environment, Food & Rural Affairs, May 2001. http://www.defra.gov.uk/environment/climatechange/trading/draft/pdf/trading.pdf [4] Guidelines for the Measurement and Reporting of Emissions in the UK Emission Trading Scheme, Department for Environment, Food & Rural Affairs, May 2001. http://www.defra.gov.uk/environment/climatechange/trading/pdf/trading-reporting.pdf	Australia Greenhouse Challenge ***Referenced Documents***: Greenhouse Challenge Evaluation Report, AGO, Canberra, 1999. [1]Developing a Cooperative Agreement (Large Companies), AGO, Canberra, 1999. http://www.greenhouse.gov.au/challenge/html/how-to-join/coop_agreement_lrg.pdf [2]"Progress Report" template.	Canada's Climate Change Voluntary Challenge ***Referenced Documents:*** Registration Guide 1999: Canada's Climate Change Voluntary Challenge & Registry Inc., Ottawa, Canada. http://www.vcr-mvr.ca/downloads/pdf/complete_guide.pdf
1. Boundary Determinations in terms of ownership vs. management control and definitions of management control, legal ownership and equity share	Direct participant's boundary determination is based on management control A Direct Participant has management control over a source when its exercises dominant influence over the emissions from a source, through having the ability to direct the financial and operating policies governing the emissions from a source. This status is generally made available through a participants consolidated financial statements. [3] [Annex A.2, 44] Examples of dominant influence: 1) by virtue of the provisions contained in its memorandum or articles; 2) through holding a majority of the voting rights in that company, and; 3) through having a right to appoint or remove the directors that hold a majority of the voting rights in that company. [3] [Annex A.4, 44]	Only businesses that operate in Australia can be included. In the case of joint ventures and part-owned subsidiaries, companies will need to determine and specify whether they will report only on their share or for the whole business. Some large jointly owned enterprises are encouraged to join under their own name. [1][p. 2]	Not addressed

Table A2. GHG Reporting Programs in Other Countries (continued)

Protocol Elements	UK Emissions Trading Program	Australia Greenhouse Challenge	Canada's Climate Change Program
2.Boundary determinations with equity changes over time with mergers, acquisitions and divestitures, and vertical integration.	A Direct Participant can acquire/divest its management control over sources outside/inside its source list through: 1. a merger/de-merger 2. acquisition/divestiture 3. insourcing/outsourcing 4. opening a new source/closing a new source For all acquisitions/divestitures of sources that meet or exceed the 'Change Threshold': Should a Direct Participant acquire management control from another Direct Participant, it must also acquire the baseline emissions and targets for those sources. Adjustments will be made to the Source List Baseline and targets of both Direct Participants. [3] [Annex B.15, p. 50] Should a Direct Participant acquire management control over any sources from outside its Source List and not from another Direct Participant, no adjustment is required to be made to its Source List, Baseline or targets until the participant elects to enter them into the Scheme as new or late entrants. [3] [Annex B.16, p. 50] In the event of acquisition of substitute sources to meet its target, whereby a Direct Participant has divested a source in its Source List, but has retained management control over the activity, the Direct Participant can retain its original Baseline. [3] [Annex B.17, p. 50-51] Should a Direct Participant divest management control within its Source List to another Direct Participant, two options will result : a) Neither Participant adjusts its Source List, Baseline and targets. Arrangements for the transfer of allowances are made accordingly b) Divesting Participant must remove divested sources, adjust its original baseline and targets and inform the ETA. The acquiring participant will add sources to its source list and adjust its baseline and target. [3] [Annex B.9, p.48-49]	Acquisitions and divestments are to be reported for the period covered by the annual report in reference to the previous annual report indicating impacts to total GHG emissions reported. [2][p. 2]	Not addressed

Table A2. GHG Reporting Programs in Other Countries (continued)

Protocol Elements	UK Emissions Trading Program		Canada's Climate Change Program
2.Boundary determinations with equity changes over time with mergers, acquisitions and divestitures **(continued)**	Should a Direct Participant divest management control within its Source List not to another Direct Participant, it will have to adjust its Source List, Baseline and targets. The acquiring company is not required to enter the Scheme. [3] [Annex B.10, p. 49-50] Definitions: Change Threshold: The threshold at which changes to company structure or operations lead to adjustments to the Source List, Baseline and targets. [3] [Annex C 53] The change threshold is 25,000 tCO_2e or 2.5 percent of total verified baseline emissions, whichever is less. [4] [Section 2, 13] source: the collection of one or more point sources of the same type within a site (where a 'point source' is any separately identifiable point from which greenhouse gases are emitted). Size threshold for a source: 10,000 tCO_2e or 1% of the source list total (which ever is less). [3][Annex C 54], [3][Sec. 2.17, p. 11] Source List: List describing the sources being brought into the Scheme. [3] [Annex C, 54] Target: A commitment to reduce emissions by a specified amount over a specified period of time. [3] [Annex C, 54]		

Table A2. GHG Reporting Programs in Other Countries

Protocol Elements	UK Emissions Trading Program	Australia Greenhouse Challenge	Canada's Climate Change Program
3. Reporting emissions from joint ownership, subsidiaries	It is not acceptable for more than one Direct Participant to claim responsibility for a single emissions source, therefore a source can only be brought into the scheme by the Direct Participant who has management control. In the case of joint ventures or ownership, a Direct Participant may be prevented from entering a particular source into the Scheme if another company has joint management control over the source and objects to its entry. In this case, the Direct Participant is allowed to exclude the source. [3] [Annex A.6, 44]	In the case of joint ventures and part-owned subsidiaries, companies will need to determine and specify whether they will report only on their share or for the whole business. Some large jointly owned enterprises are encouraged to join under their own name. [1][p. 2]	Not addressed.
4. Determine the level of reporting detail whether at source, project or facility level.	Direct participants, which can be a single organization or group of other organizations, will enter one or more sources into the Scheme generating a source list. For each site, a source is the collection of one or more point sources of the same type, where a point source is any separately identifiable point from which greenhouse gases are emitted. [3] [Section 2, 9-10] Size threshold for a source: 10,000 tCO_2e or 1% of the source list total (which ever is less). [3][Sec. 2.17, p. 11]	Companies with operations at more than one site must report on individual sites and also provide an aggregate of the total emissions inventory. The AGO encourages participants to identify all economically viable emission reduction activities. For each action, a cost-benefit analysis and expected emission reductions, or targets, must be included. Targets should be simple and measurable. Companies dealing with different sites individually will benefit from setting separate goals for each site in addition to an overall expected abatement. [1][p. 2]	Level of reporting is very flexible. Reporting can be classified by region, facility, and types of emission or by any other system. Intent is to allow management the ability to review GHG emissions or energy consumption when planning the development of new facilities or making revisions to existing operations. The report should be an integral part of the ongoing planning process. [p. 10]

Table A2. GHG Reporting Programs in Other Countries (continued)

Protocol Elements	UK Emissions Trading Program	Australia Greenhouse Challenge	Canada's Climate Change Program
5. Determine additional information necessary and level of detail such as geographical distribution: CA, US, worldwide	The scope for reporting emissions does not extend beyond the scope of the UK national inventory. Multinational corporations wishing to compile emissions inventories for their whole organization may use the methodology, however, the emissions associated with UK-based operations must be separately identifiable. [4] [Section 4, 10] In addition to emissions from energy use by fuel Direct Participants shall also record the following: • Identify any changes in management control to individual sources above the 'Change Threshold'. • Provide evidence showing divested source list items to another Direct Participant • Provide evidence of any contractual arrangements for maintaining a source in the Baseline in the case of divestment or acquisition • Provide evidence of substitute sources that are added to the Source List. [4] [Section 6, 16] Suggested reporting elements in addition to energy use by fuel include: • Allowances bought/sold in the UK ETS, • Qualitative performance measures for targets, • Measure of output for efficiency targets. The UK Climate Change Program contains targets rather than whole sites or whole companies, a recommendation is made to obtain facility maps with the following information: • The boundary of the energy intensive installation(s) in relation to the boundary of the facility, for all facilities; • For facilities that do not occupy an entire site, the boundaries of the site and the energy intensive facility within it; • Location of incoming energy supplies and location of utilities meters; • In-situ generated sources of energy; • Location of meters recording exports; • Location of sub-meters within the facility. [4] [Section 6, 16]	Every 12 months companies should report on their progress in a "Progress Report". The progress report contains a description of a company's progress relative to its action plan. A new emissions inventory, and a description of new actions. Actions not undertaken in previous reports should be noted with reasons given. • The plan must contain key performance indicators (KPI's), or efficiency indicators. • The plan also must contain a two year rolling forecast of emissions. To ensure consistent reporting of forecast savings, companies are asked to report against a reference year prior to the implementation of the company action plan. • The plan should contain a public profile that includes a brief description of your company and a summary of your company's action plan and its expected GHG emissions savings. The report should include all CO_2–e emissions and all other GHG emissions that represent at least 5% or 50,000 tonnes (whichever is lowest) of total CO_2-e emissions by the company. Regarding spatial boundaries, only businesses that operate in Australia can be included in the plan. Members are encouraged to report to the level of major sites and aggregate minor sites. Members are encouraged to report any international actions such as emissions trading.	Baseline information: • Region • Facility/business unit • Process • Output stream • Indirect/direct emissions • Year/month • Time of year (quarter or season) • GHG gas type • Emission reduction project [p. 10] From reporting form: Executive summary Organization Profile Senior Management support: • Signed statement of Endorsement • Internal Practices and Management systems Base Year – Methodology & Quantification Projection – Methodology & Quantification Target Setting – Methodology & Quantification Measures to Achieve targets • List of key activities • Estimated Impact of Activities/projects Results achieved • Current reporting year • Interim years • Verification • Offsets Education, Training and Awareness

Table A2. GHG Reporting Programs in Other Countries (continued)

Protocol Elements	UK Emissions Trading Program	Australia Greenhouse Challenge	Canada's Climate Change Program
6. Describe the issues surrounding direct and indirect emissions	Direct Participants will enter sources of both direct and indirect emissions from energy usage into the Scheme. They will include indirect emission from energy used on-site but generated off-site. They will also include direct emissions from energy both generated and used on-site. [3] [Section 2, p. 9] Any heat or electricity exported from a site will not be counted in a Direct Participant's sources. [4] [Section 4, p. 11] Additional emissions that cannot be included in a Direct Participant's Source List: 1. Emissions from facilities within a target unit covered by any other financial incentive agreement; 2. Emissions from land and water transport ; 3. Methane emissions from landfill sites covered by the Landfill Directive; and, 4. Emissions from households. [3] [Section 2, p. 9]	Progress reports should include direct emissions by source and indirect emissions associated with electricity purchased by the member and organic waste sent to landfill by the member. [2][p. 3]	"In a perfect world, every VCR Inc. report would include all GHG emission sources, both direct and indirect." Direct emissions are defined as those that are directly influenced by your organization's operations. This would include any on-site combustion process or fugitive emissions. Indirect emissions are those associated with an outside organization that supplies energy. Electricity generation is the most common, but off-site steam generation and district heating systems may also be considered indirect emissions [p. 9]

Table A2. GHG Reporting Programs in Other Countries (continued)

Protocol Elements	UK Emissions Trading Program	Australia Greenhouse Challenge	Canada's Climate Change Program
7. Outsourcing, subcontracting and changes to baselines	The UK ETS defines a Source List that accounts for the inclusion of sources relative to outsourcing/insourcing and subcontracting. Any changes larger than the Change Threshold are reflected in the Source List, Baseline and targets of the Direct Participants in the same manner as acquisitions and divestitures (see item 2). [4] [Section 4, 10]	Participants must report major changes in operations and the percentage change. Major changes include shifts in operations, interruptions and new activities. Major changes are referenced to the previous year's progress report.	The registry will accept any base year inventory (base) for registration. The base need only be documented once, however, participant must revisit base to update analysis, add facilities or alter the scope of operations. The methodology used should be included. Sources reported and not reported should be listed (e.g. reporting of sub-contracted custodians) [p. 8-9]
8. Reporting procedures for participants that choose to report greenhouse emissions on a statewide basis need to show: A) Changes in a participant's operations that result in a long-term shift from CA to other states. B) Corresponding change in the participant's baseline	Because the Scheme boundary is limited to UK emissions, multinational corporations must differentiate all sources associated with UK-based operations as part of their Source List. A change in a participants operations that would result in a revision to the Source list would be captured by the reporting requirements and reflected in Baseline and target changes. [4] [Section 4, 10]		Not addressed

Table A3. Air Pollutant Reporting in Selected California Programs

	Specific Programs			
Protocol Elements	CARB's Interchangeable Air Pollution Emission Reduction Credits **http://arbis.arb.ca.gov/regact/ierc/ierc.htm**	SMAQMD Emission Reduction Credits http://www.arb.ca.gov/DRDB/SAC/CURHTML/R204.HTM	San Diego Air Pollution Control District Rule 27 on Mobile Source Emission Reduction Credits	South Coast AQMD RECLAIM program – stationary sources http://www.aqmd.gov/rules/rulesreg.html (rules XX: 2000-2020)
1. Boundary Determinations in terms of ownership vs. management control and definitions of management control, legal ownership and equity share	The regulation establishes a statewide methodology for use by individual air districts when calculating the value of emissions reduction credits. Districts, in consultation with the Air Resources Board, shall adopt enforceable technical protocols that define how emission reductions will be calculated for purposes of certifying them as interchangeable credits. [91506.(c)]	Emission Reduction Credits (Rule 204-206) do not define boundary determinations but do address some of the boundary issues. The Emission Reduction Credits are obtained for mobile or stationary sources. In order to obtain reduction credits for mobile sources, the rule refers to Compliance Plans that include monthly recording and auditing but does not state who is responsible for completing the plans and who owns the credit. (Rule 201 - 403.2). With respect to equity share, multiple owners of emission credits shall be separated according to agreements, filed with the District, between the owners with one emission reduction credits Certificate issues to each owner for their respective portion. (Rule 204 410.4)	Rule 27 does not define management control, legal ownership and equity share. For the vehicle retirement program, a mobile source emission reduction credit (MERC) is obtained by the operator of an accelerated vehicle retirement program. (c)(1)(i)(D) Rule 27 refers only to "applicants" and does not describe any boundaries. (c)(1)(ii) However, the applicant must be in possession of the current DMV registration. Therefore, normally only the owner of the vehicle may obtain a MERC. (c)(1)(ii)(G) The Air Pollution Control Officer may issue a MERC certificate to an applicant who does not hold title to the vehicle for which a MERC is requested only if such applicant provides written proof of the title holder's transfer of interest in the MERC to the applicant. (c)(4)(iii)	RECLAIM permits "facilities". FACILITY means any source or grouping of sources or other air contaminant-emitting activities which are located on one or more contiguous properties within the Basin, and are owned or operated by the same person. Rule 2000 (c)(37) The entity responsible for controlling emissions and obtaining credits is the facility or its management. This may be the facility's owner but it is not required to be so. A non-RECLAIM facility may elect to enter the program if the owner or operator files for an Application of Entry. Rule 2001 (f)(1)(A) Once a facility is in the RECLAIM program, it may not opt out, even if its emissions drop below 4 tons per year.

Table A3. Air Pollutant Reporting in Selected California Programs (continued)

Protocol Elements	*CARB's Emission Credits*	SMAQMD Emission Credits	Rule 27	RECLAIM program
2.Boundary determinations with equity changes over time with mergers, acquisitions and divestitures, and vertical integration	The regulation does not address these boundary determinations.	The rules do not address these issues.	If ownership of a motor vehicle for which a MERC was previously granted is transferred, a copy of the written conveyance describing the transaction must be filed with the District. (c)(5)(iii)	The RECLAIM facility listings are amended if there is a change in a facility name. Rule 2001 (c)(1)(B) Also, if a non-RECLAIM facility generates more than four tons of NOx or SOx in a year, the facility listings are amended to add the facility. Rule 2001 (c)(1)(D) If a facility grows due to acquisitions, its baseline is not augmented. Either the facility being added must have credits available or the acquiring facility must purchase credits or offset emissions. In the case of a divestiture, the credits can either be sold with the facility or kept by the original owner.
3. Reporting emissions from joint ownership, subsidiaries	The regulation does not address reporting requirements from join ownership or subsidiaries.	The rules do not address joint ownership or subsidiaries except for the joint equity distribution mentioned above.	Rule 27 does not address joint ownership or subsidiaries.	The manner in which a facility deals with partial equity is up to the companies involved. RECLAIM only requires that there be a registered entity that is authorized to make trades.

Table A3. Air Pollutant Reporting in Selected California Programs (continued)

Protocol Elements	**CARB's Emission Credits**	**SMAQMD Emission Credits**	Rule 27	**RECLAIM program**
4. Determine the level of reporting detail whether at source, project or facility level.	The regulation does not specify at which level emissions are reported.	Reporting of emissions is done at the equipment level. Every piece of equipment that is not exempt must be permitted, according to Rule 201. Under Rule 206, mobile source emissions are reported at the fleet level.	Emissions are reported at the owner level but for each vehicle. The owner may obtain a MERC for each vehicle whose emissions are being reduced by scrappage, replacement, or retrofit. This is true in sections (ii), and (iii), and (iv).	The prospective Facility Permit holder shall identify each source of RECLAIM pollutants located at the facility, and shall submit equipment descriptions and operating parameters for such sources if required by the Executive Officer. Rule 2006 (b)(2) Facilities are subject to RECLAIM if their emission fee for any year since 1990 shows emissions of more than four tons of NOx or SOx. However, this excludes any NOx or SOx process unit which is rental equipment with a valid District Permit to Operate issued to a party other than the facility. Rule 2001 (b)(1)(B). A third party may be hired to assess the emissions sources at the facility level.
5. Determine additional information necessary and level of detail such as geographical distribution. CA, US, worldwide	Districts shall provide procedures that include in the reporting: • emissions rate • operation period • activity level • technical uncertainty for each pollutant	The rules are concerned only with emissions in the Sacramento Air Basin. For mobile source emission reductions attributable to new vehicles, mileage projections for lower emitting vehicles and plans including monthly records of mileage inside and outside the air basin are required. (Rule 206 403.1-.2)	For fleet vehicles in section (iv), applicants must show that they are reducing emissions that would have occurred in San Diego County. This may require a log of odometer readings sufficient to demonstrate mileage traveled inside and outside the County. (c)(1)(iv)(D)(8)	RECLAIM is only concerned with emissions in the South Coast Air District. As a result, only facilities emitting in the Air District participate in the program.

Table A3. Air Pollutant Reporting in Selected California Programs (continued)

Protocol Elements	CARB's Emission Credits	SMAQMD Emission Credits	Rule 27	RECLAIM program
6. Describe the issues surrounding direct and indirect emissions	The regulation does not address direct versus indirect emissions.	The rules only address direct emissions.	Rule 27 only addresses direct emissions from motor vehicles	RECLAIM covers only direct emissions from facilities in the Air District – e.g. electricity emissions are counted under the generating facilities, not the facilities using electricity. Rule 2001 (i)(1)(D)
7. Outsourcing, subcontracting and changes to baselines	The regulation does not address outsourcing or subcontracting. The Districts' calculation protocols must include: Procedures to incorporate emissions inventory updates and changes in source category baselines. 91507. (b)(4)	The rules do not address outsourcing or subcontracting.	Rule 27 does not address outsourcing or subcontracting. Baseline emissions are defined as annual emissions generated within the District from a mobile source prior to its use in a MERC Program.	Outsourcing and subcontracting effectively reduces a facility's emissions under RECLAIM since its inventory only includes emissions from the facility itself.
8. Reporting procedures for participants that choose to report greenhouse emissions on a statewide basis that require participants to show both of the following: A) Changes in a participant's operations B) Corresponding change in the participant's baseline	The regulation does not address changes in reporting based on location changes or changes in a name of a participant.	Emission reductions attributable to a proposed control measure must be considered surplus emissions. Usually this means reductions in excess of any required control or already attributed to other control measures. In Rule 206, however, emission reductions may be eligible as surplus if the control measures are already identified in the State Implementation Plan but no rule has been adopted within two years from the scheduled adoption date (211.1).	There are no reporting procedures associated with changes in participants' operations or their baselines. Since MERCs are granted for reductions associated with a particular vehicle, a change in the operations of an applicant will not affect the baseline emissions for that vehicle. Rule 27 applies only to San Diego county and counts only emissions in the county. If vehicles are imported from outside San Diego, California, or the US, to replace those retired in the program, there appears to be no emissions reductions in San Diego even though there may be if accounted for globally.	Since RECLAIM covers only emissions in the South Coast Air District, any start up of facilities in the District that produces more than four tons of NOx or SOx per year must participate in RECLAIM. The baseline emissions remain constant regardless of changes in the structure or location within the South Coast.

Appendix B. Review Non-Combustion Greenhouse Gas Emissions Estimation Methodologies used in the California Statewide GHG Inventory

The "Inventory of California's Non-Combustion Greenhouse Gas Emissions" (CEC, 2001) was reviewed and some of the estimation methodologies presented were summarized. Those results are presented in this appendix. Italics are used to represent either a direct quote or paraphrasing from the inventory.

Agricultural Residue Burning

CO_2

State-wide Methodology: *The method used to estimate emissions form open burning of agricultural crop wastes in California was created by B.M. Jenkins and his colleagues at the University of California at Davis (Jenkins and Turn 1994, Jenkins et al. 1992). Jenkins developed parameters for six crops – almonds, walnuts, wheat, barley, corn, and rice – which account for 97 percent of agricultural biomass burned in California. Wildfires are not included. Each crop specific emission is calculated as follows:*

$$\boxed{\text{Emissions} = \text{Production Area} \times \text{Residue Yield} \times \text{Burn Fraction} \times \text{Emission Factor}}$$

Where:
Emission Factor is specific to the emission being calculated. See Data Source for factor locations.
Production Area is the crop production area in acres.
Residue Yield and Burn Fraction are estimation parameters.

Data Source: Crop production acreage data were obtained from the Crop Reports published by the California County Agricultural Commissioners (1990-2000). The parameters (burn fractions, residue yields, and CO_2 emission factors) were taken from Jenkins et al. (1992) and Jenkins and Turn (1994).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the acreage of the production area for each crop, which should be readily available.

CH_4

State-wide Methodology: *The method used to estimate emissions from open burning of agricultural crop wastes in California was created by B.M. Jenkins and his colleagues at the University of California at Davis (Jenkins and Turn 1994, Jenkins et al. 1992). Jenkins developed parameters for six crops – almonds, walnuts, wheat, barley, corn, and rice – which account for 97 percent of agricultural biomass burned in California. Wildfires are not included. Each crop specific emission is calculated as follows:*

$$\boxed{\text{Emissions} = \text{Production Area} \times \text{Residue Yield} \times \text{Burn Fraction} \times \text{Emission Factor}}$$

Where:
Emission Factor is specific to the emission being calculated.
Production Area is the crop production area in acres
Residue Yield and Burn Fraction are estimation parameters.

Data Source: Crop production acreage data were obtained from the Crop Reports published by the California County Agricultural Commissioners (1990-2000). The parameters (burn fractions, residue yields, and CH_4 emission factors) were taken from Jenkins et al. (1992) and Jenkins and Turn (1994).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the acreage of the production area for each crop, which should be readily available.

N_2O

State-wide Methodology: *The method used to estimate emissions form open burning of agricultural crop wastes in California was created by B.M. Jenkins and his colleagues at the University of California at Davis (Jenkins and Turn 1994, Jenkins et al. 1992). Jenkins devoloped parameters for six crops – almonds, walnuts, wheat, barley, corn, and rice – which account for 97 percent of agricultural biomass burned in California. Wildfires are not included. Each crop specific emission is calculated as follows:*

Emissions = Production Area x Residue Yield x Burn Fraction x Emission Factor

Where:
Emission Factor is specific to the emission being calculated
Production Area is the crop production area in acres
Residue Yield and Burn Fraction are estimation parameters

Data Source: Crop production acreage data were obtained from the Crop Reports published by the California County Agricultural Commissioners (1990-2000). The parameters (burn fractions and residue yields) were taken from Jenkins et al. (1992) and Jenkins and Turn (1994). N_2O emissions factors were derived from the emission factors for NO_x using the ratios of NO_x-N/N and N_2O -N/N provided in the IPCC guidelines (Jenkins and Turn 1994, IPCC/UNEP/OECD/IEA 1997).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the acreage of the production area for each crop, which should be readily available.

Agricultural Soil Management

N_2O

State-wide Methodology: *Nitrous oxide emissions from agricultural soil management were estimated using methods found in the EIIP guidance (EIIP 1999) and the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) as amended by the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000).*

There are three types of N_2O emissions from soils:

1. *Direct emissions from managed soils, where the N_2O is emitted from nitrogen-related cropping practices*

Estimates were based on the amount of nitrogen deposited annually on managed soils in the following forms: (1) commercial fertilizer application; (2) manure application; (3) production of nitrogen-fixing crops; (4) nitrogen returned to soils; and (5) cultivation of high-organic content soils. Following methodologies used in the U.S. Inventory (EPA 2001), the nitrogen was calculated for each animal type:

Amount of Nitrogen in Manure = Animal Population (head) x TAM (kg/head) x Kjeldahl nitrogen emission factor (kg N/1000 kg animal mass/day) x 365 days/year
Amount of Nitrogen Returned to Soils from N-fixing Crops (kg N) = Crop Production (kg) x (1 + ratio of residue mass to crop mass (kg residue/ kg crop)) x Dry Matter Fraction of Residue (kg dm/kg residue) x Fraction of Residue Applied x Nitrogen Content (kg N/kg dm)

Estimates of annual emissions of N_2O resulting from histosol cultivation were based on the total acreage of histosols in California that are cultivated each year. These areas were multiplied by an emission factor for histosols (kg N2O-N/ha=yr) in order to estimate emissions from this source (IPCC 2000, EIIP 1999).

2. *direct emissions from livestock manure deposited on pasture, range, and paddock; and*

Emissions are based on the amount of nitrogen in manure for each animal type.

Amount of nitrogen in Manure (kg N/year) = Animal Population (head) x TAM (kg/head) x Kjeldahl nitrogen emission factor (kg N/1000 kg animal mass/day) x 365 (days/year)

TAM data for dairy cattle, beef cattle, swine, and poultry were taken from the U.S. Inventory (EPA 2001). TAM data for sheep, goats, and horses, and Kjeldahl nitrogen emission factors for all livestock are from the EIIP guidelines (1999).

3. *indirect emissions where nitrogen containing compounds are released to the atmosphere or groundwater and following denitrification/nitrification are emitted as N2O.*

Estimates from indirect N_2O emissions from soils include:

(1) volatilization of NH_3 and NO_x from nitrogen deposition in fertilizer application and livestock manure;

Fertilizer and manure emissions were calculated by multiplying the volatilized portion of each source's total nitrogen content by an emission factor of 1 percent. This factor reflects the ratio of nitrogen emitted as N2O to total volatile nitrogen.

(2) leaching and runoff of nitrogen from agricultural fields.

Emissions from leaching and runoff are a function of the portion of unvolatilized nitrogen from manure and fertilizers that enter groundwater. Following guidance developed by EIIP(1999) and IPCC(2000), as well as methods used in U.S. Inventory (EPA 2001), estimates of indirect emissions are baed on the following assumptions: 30 percent of the unvolatilized nitrogen in fertilizer and manure enter leachate and runoff, and 2.5 percent of groundwater nitrogen is emitted as N_2O.

Data Source: Fertilizer consumption data was obtained from Fertilizing Materials Tonnage Reports, published by the California Department of Food and Agriculture (CDFA 1992 – 2000) Crop production data were taken from Crop Reports, released by the California County Agricultural Commissioners (CCAC 2001). The animal population data sets used for the manure management emissions estimates were used to estimate N_2O emissions from agricultural soils as well (EPA 2001, AHC 1996, FAO 2001, USDA 200a-g, USDA 1999a-d, USDA 1998a-b, USDA 1994a-b). Histosol cultivation acreage was estimated based on the expert judgement of two California Sata soil scientists (Vinson 2001, Simpson 2001). All emission factors and conversion factors can be found in the EIIP guidance (1999), IPCC guidance (2000), or the U.S. Inventory (EPA 2001).

Applicability: The fundamental concept behind the methodology could be used on an individual company basis. However, the procedure needs to be more clearly defined.

Carbon Dioxide Consumption

CO_2

State-wide Methodology: *Carbon dioxide emission estimates were based on the assumption that, except for enhanced oil recovery, all end-use applications release 100 percent of the CO_2 manufactured. State levels were taken as a percentage of National totals.*

State CO_2 Emissions = National CO_2 Emissions x State Production Capacity / National Production Capacity.

Data Source: National CO_2 emissions data were obtained from the U.S. Inventory (EPA 2001).

Applicability: Methodology used to estimate California state emissions is not applicable on an individual company basis. Since CO_2 emissions for individual companies are based on many attributes of the facility and not simple as a percentage compared with the national production capacity, a new methodology must be developed.

Cement Production

CO_2

State-wide Methodology: *Estimates of CO_2 emissions from cement production were based on the following equation presented in EIIP Volume VIII: Estimating Greenhouse Gas Emissions (EIIP 1999):*

CO_2 Emissions = Clinker Production x CaO Content(%) x 0.785 x CKD Correction Factor

Where:
Clinker Production is the mass of clinker produced.
CaO Content(%) is the percent of lime content of the clinker, default is 65%.
0.785 = CO_2/CaO stoichiometric ratio.
The CKD (Cement Kiln Dust) is largely a mix of calcinated and uncalcinated raw materials and clinker, and accounts for the portion of materials that does not become part of the clinker, and is lost to the system. IPCC recommends that CKD CO_2 emissions should be estimated as 2 percent of the CO_2 emissions from clinker production (IPCC 2000). Hence, the CKD correction factor is 1.02.

Data Source: Lime content of clinker and the CKD correction factor were obtained from the IPCC Good Practice Guidance (IPCC 2000).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the mass of clinker produced, which should be readily available.

Coal Mining

CH_4

State-wide Methodology: *Emissions are composed of data from surface mines as well as from post-mining operations. Estimated with EIIP guidance (EIIP 1999)*

Emissions from surface mines (ft^3 CH_4) = Surface Coal Production (short tons) x 6.4 (ft^3 CH_4/short tons)

Emissions from post-mining operations (ft^3 CH_4) = Surface Coal Production (short tons) x 1.04 (ft^3 CH_4/short ton)

Emissions = Emissions from surface mines (ft^3 CH_4) + Emissions from post-mining operations (ft^3 CH_4)

Data Source: Data on coal production obtained from the Coal Industry Annual, Department of Energy (1990-1999). This data was confirmed with the California Division of Mines and Tunneling (2001) and the California Department of Mines and Geology (2001).

The Emission factors for surface mining operations were taken from the EIIP guidance and U.S. Inventory (EIIP 1999, EPA 2001). Both emissions factors were not California specific, but rather a factor used for a large amount of states without significant sources of mining. 6.4 ft^3/short ton is a basin-specific methane emission factor which accounts for methane liberated from the coal itself and from surrounding strata. 1.04 (ft^3 CH_4/short ton) is a basin-specific post-mining methane emission factor used for California.

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the mass of surface coal production, which should be readily available. This methodology does not include underground mines since none were present in California from 1990 to 1999. Underground mines generate the largest amount of emissions as compared to surface mines, so if underground mines are identified, a new methodology will need to be developed to include those emissions.

Electric Utilities

SF_6

State-wide Methodology: *Since state-level SF_6 data are not available, state guidance provided in the EIIP guidance recommends that SF_6 emissions be estimated using a percent total of the national emissions level:*

State SF_6 Emissions = National SF_6 Emissions x State Electricity Consumption / National Electricity Consumption.

Data Source: National SF_6 emissions estimates were obtained from the US inventory (EPA 2001).

Applicability: Methodology used to estimate California state emissions is not applicable on an individual company basis. This methodology simply determines a percentage of the national total that an entity consumes to determine its emissions. If an entity does not have any processes that emit SF_6, it would incorrectly report emissions. Therefore, a new methodology must be developed.

Enteric Fermentation

CH_4

State-wide Methodology: *Due to their large population, large size, and particular digestive characteristics, cattle account for the majority of* CH_4 *emissions from livestock. Additionally, cattle production systems are better characterized in comparison with other livestock management systems. As a result, a more detailed methodology, i.e., Intergovernmental Panel on Climate Change (IPCC) Tier 2, was used for estimating emissions from cattle. While emissions for sheep, goats, swine, and horses were handled using the simpler IPCC Tier 1 approach.*

The methodology for estimating emissions from enteric fermentation is based on the methodology utilized in the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999 (EPA 2001), where it is described in four steps:

1. *Characterize the Cattle Population*
2. *Characterize the Cattle Nutrition*
3. *Determine Cattle Emissions*
4. *Determine Other Livestock Emissions*

Characterize the Cattle Population:

Each stage in the cattle life cycle was modeled to simulate the cattle population from birth to slaughter. This level of detail accounts for the variability in methane emissions associated with each life stage.

The categories used to estimate population include:
- *calves*
- *dairy cows*
- *dairy heifer replacements*
- *beef cows*
- *beef heifer replacements*
- *heifer and steer stockers*
- *feedlot animals; and*
- *bulls.*

The statistics gathered for each category include birth estimates, end of year population data, feedlot placement information, and slaughter weight data. Other performance factors, such as pregnancy, lactation, average weights, and weight gain, are also tracked for each of the cattle population categories.

Characterize Cattle Nutrition:

To support development of digestible energy (DE) and methane conversion rate (Ym), data were collected on diets considered representative of different regions. DE and Ym values were estimated for each cattle population category based on physiological modeling and expert opinion. DE and Ym values for dairy cows and most grazing animals were estimated using a model (Donovan and Baldwin 1999) that represents physiological processes in the ruminant animals. Three major categories of input required by the model are animal description (e.g., cattle type, mature weight), animal performance (e.g., initial and final weight, age at start of period), and feed characteristics (e.g., chemical composition, habitat, grain or forage).

For feedlot animals, DE and Ym values were taken from Johnson (1999). Values from dairy replacement heifers are based on EPA (1993). These diet characteristics are used to implement the equations described for Tier 2 in the Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.

Determine Cattle Emissions:

In order to estimate methane emissions from cattle, the population was divided into region, age, sub-type (e.g., calves, heifer replacements, cows, etc.), and production (i.e., pregnant, lactating, etc.) groupings to more fully capture any differences in methane emissions from these animal types. Cattle diet characteristics developed under Step 2 were used to develop regional emission factors for each sub-category. Tier 2 equations from IPCC (2000) were used to produce methane emission factors for the following cattle types: dairy cows, beef cows, diary replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, heifer feedlot animals, and steer and heifer feedlot step-up diet animas. To estimate emission from cattle. Populations data were multiplied by the emission factor for each cattle type. (EPA 2001)

Determine Other Livestock Emissions:

Emissions estimates for other animals types, including sheep, goats, swine, and horses, were based upong average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH_4 *emissions from livestock in California from 1990 through 1999.*

Data Source: Data for non-equine animal populations was compiled from data collected by the California Agricultural Statistics Service (CASS) (Coe 2001) and published in National Agricultural Statistics Service (NASS) of the U.S. Department of Agriculture (USDA 1994a-b, 1995a-b, 1996, 1997, 1998a-b, 1999a-b, 2000a-e). Since equine data was not available, the equine population was estimated using data for 1995 from the American Horse Council (AHC 1996) in conjunction with national population statisitics available from the Food and Agriculture Organization (FAO 2001). Emission factors for bulls and other livestock were obtained from the Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000).

Applicability: The fundamental concept behind the methodology could be used on an individual company basis. However, the procedure needs to be more clearly defined.

Human Sewage

N_2O

State-wide Methodology: *Nitrous oxide emissions from sewage in wastewater were estimated using the following equation taken from EIIP guidance (EIIP 1999):*

$$N_2O \text{ Emissions} = \text{Protein} \times \text{FRACnpr} \times \text{Population} \times EF$$

Where:
Protein = Annual per capita protein consumption
FRACnpr = Fraction of nitrogen in protein (percent)
EF = Emission factor (kg N20-N/kg sewage-N produced)

Data Source: Annual per capita protein intake data was taken from the U.S. Inventory (EPA 2001). The fraction of nitrogen in protein and the N_2O emission factor was obtained from IPCC (2000).

Applicability: Methodology could be successfully used, assuming minor changes, on an individual company basis since the only on-site measurement that needs to be made is the population, which should be readily available. Minor changes would have to take into account the time that is spent at work versus time spent away from work.

Landfills

CH_4

State-wide Methodology: *As per the EIIP Volume VIII: Estimating Greenhouse Gas Emissions (EIIP 1999), emissions from landfills were estimated as the total amount of CH_4 produced from municipal landfills, plus the CH_4 produced by industrial landfills, minus the CH_4 recovered and combusted, minus the CH_4 oxidized before being released into the atmosphere. The following steps are shown:*

Step 1 – Estimate Total Waste-In-Place (WIPtotal) at Municipal Landfills
Estimated by multiplying per capita disposal rates by the population.

Step 2 – Estimate Total Methane Generation
In order to estimate the generation from municipal landfills, the following information was needed: (1) the amount of WIP in small vs large landfills, and (2) rainfall.

Small landfills: Using EIIP's equations:

$$CH_4 \text{ (tons } CH_4\text{/yr)} = \text{WIPsmall (tons)} \times 0.27 \text{ (ft}^3\text{/day/ton)} \times 0.0077 \text{ (tons } CH^4\text{-day/yr-ft}^3\text{)}$$

Where:
WIPsmall = WIPtotal x 14 percent
14 Percent is the amount of waste that was stored in a small landfill in California between 1990 and 1999.

Large landfills:

$$CH_4\ (tons\ CH^4/yr) = N \times [417{,}957 + [0.16 \times (Ave\ WIPlarge\ (tons))] \times 0.0077\ (tons\ CH_4\text{-}day/yr\text{-}ft^3)$$

Where:
N = Number of large landfills
Average WIPlarge = WIPlarge/N
WIPlarge = WIPtotal x 86 percent
86 Percent is the amount of waste that was stored in a large landfill in California between 1990 and 1999.

Industrial landfills (EIIP guidelines 1999):

$$CH_4\ (tons\ CH_4/yr) = 0.07 \times CH_4\ emissions\ from\ municipal\ landfills$$

Step 3 – Estimate and Adjust for Methane Recovery and Oxidation
The amount of CH_4 recovered through flaring or LFGTE projects was estimated using data and methods presented in the U.S. Inventory (EPA 2001a). Flare estimates were based on sales data collected from flare equipment vendors. Calculations were done state wide and not on an individual basis.

Data Source: EIIP guidelines (1999) provided most data and estimating methodologies. The U.S. Inventory (EPA 2001a) provided methane-recovering data.

Applicability: The fundamental concept behind the methodology could be used on an individual company basis. However, the procedure needs to be more clearly defined. Specifically, determining the threshold value of a small vs. a large landfill needs to be defined.

Lime Production

CO_2

State-wide Methodology: *CO_2 emissions from lime manufacturing were based on the following equation presented in the EIIP guidance (EIIP 1999):*

$$CO_2\ Emissions = Lime\ Production \times 0.785$$

Where:
Lime Production is the mass of lime produced

The 0.785 conversion factor is used to obtain the total metric tons of CO_2 emitted. It is the stoichiometric ratio of CO_2 /CaO.

Data Source: The conversion factor is the result of multiplying the quantity of lime (CaO) produced by its respective CO_2/CaO stoichiometric ratio. The CO_2/CaO stoichiometric ratio: molecular weight of CO_2 (44g)/molecular weight of CaO (56g) = 0.785.

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the mass of lime produced, which should be readily available.

Limestone and Dolomite Consumption

CO_2

State-wide Methodology: Data was unavailable and state level calculations were based as a percentage of the US total:

State emissions = National Emissions x California Limestone and Dolomite Consumption / National Limestone and Dolomite Consumption

It was assumed that the ratio would be consistent with the use of limestone and dolomite for CO_2-producing activities at the state level.

Data Source: National CO_2 emissions from limestone and dolomite consumption were obtained from the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999 (EPA 2001).

Applicability: Methodology used to estimate California state emissions is not applicable on an individual company basis. This methodology simply determines the percentage of the national total that an entity consumes and uses that to determine the entity's emissions. Since emissions are based on more than just the amount consumed, a new methodology must be developed.

Manure Management

CH_4

State-wide Methodology: *The main factor of CH_4 emissions form this source is the quantity of volatile solids produced by livestock. The equations below outline the process of calculating CH_4 Emissions:*

Volatile Solids = Livestock population x TAM x ratio of volatile solids to TAM

Potential CH_4 Emissions = Volatile Solids x GCF

CH_4 Emissions = Potential CH_4 Emissions x MCF

Where:
TAM = Typical Animal Mass Factor
GCF = CH_4 Generating Capacity Factor
MCF = accounts for the percent of the population in each management system and the effect that each particular management system has on CH_4 emissions. This number is between 0 and 1, with 0 representing extensive manure management systems and 1 representing no manure management system.

Data Source: Data for non-equine animal populations was compiled by the California Agricultural Statistics Service (CASS) (Coe 2001) and published in reports issued by the National Agricultural Statistics Service (NASS) of the US Department of Agriculture. Where possible, data was taken from U.S. Inventory (EPA 2001). Other data was taken from the EIIP guidance (EPA 2001, EIIP 1999).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the livestock population, which should be readily available. Since the emissions calculation is largely based on the MCF, a detailed system on estimated the MCF would be needed.

N_2O

State-wide Methodology: *The main factor of N_2O emissions is the amount of unvolatized nitrogen in manure, either organically bound or in the form of ammonia. The steps below highlight the process on calculating the N_2O emissions:*

Kjeldahl Nitrogen = Animal Population x TAM x ratio of TAM to Kjeldahl Nitrogen

Unvolatilized Nitrogen = Kjeldahl Nitrogen x 0.80

N_2O Emissions = Unvolatilized Nitrogen x EF

Where:
TAM = Total Animal Mass
0.80 = Percent of nitrogen assumed unvolitalized
EF = Emission factor weighted by the management systems used.

Data Source: Data for non-equine animal populations was compiled by the California Agricultural Statistics Service (CASS) (Coe 2001) and published in reports issued by the National Agricultural Statistics Service (NASS) of the US Department of Agriculture. Where possible, data was taken from U.S. Inventory (EPA 2001). Other data was taken from the EIIP guidance (EPA 2001, EIIP 1999).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the nitric acid production, which should be readily available

Municipal Wastewater

CH_4

State-wide Methodology: *Methane emissions from wastewater were estimated using the following equation taken from EIIP Volume VIII, Estimating Greenhouse Gas Emissions (1999):*

$$CH_4 \text{ Emissions} = \text{Population} \times D \times FTA \times EF \times 365$$

Where:
D = Organic Load in BOD per person (Default = 6 x 10^-8 Gg BOD/person/day)
FTA = Fraction of BOD that degrades anaerobically (Default = 15 percent)
EF = Emission Factor (Default = 0.6 Gg CH_4/Gg BOD)
365 = To convert values to annual emissions

Data Sources: Organic load and CH_4 emission factors are based on the IPCC guideline defaults (2000), while the fraction of BOD treated anaerobically is taken from the EIIP guidance (1999).

Applicability: Methodology could be successfully used, assuming minor changes, on an individual company basis since the only on-site measurement that needs to be made is the population, which should be readily available. Minor changes would have to take into account the time that is spent at work and the new Organic Load in BOD per person that is applicable. The default value would not be valid.

Natural Gas Systems

CH_4

State-wide Methodology: *The natural gas system is characterized by four major stages: field production, processing, transmission and storage, and distribution. Methane emissions from the natural gas system were estimated using methodology described in the EIIP guidance (EIIP 1999).*

$$CH_4 \text{ Emissions} = \text{Sum of (Activity Data} \times EF\text{) for each of the four major stages}$$

Where:
Activity Data = Statistics on gas production, number of wells, miles of various pipe, and other statistics that characterize the Californian natural gas system infrastructure and operations; and
EF = Emission Factor (metric tons CH_4/unit)

Data Source: The activity data compiled for each of the four major stages includes: number of associates/non-associated wells (CDC 2001a); number of offshore platforms (CDC 2001a); miles of gathering, transmission, distribution and services pipeline (DOT 2001); number of processing facilities (O&J 1997-2001); number of transmission facilities (EIA 2001); and number of storage fields (CDC 2001b).

The data source for the EF was unknown.

Applicability: The fundamental concept behind the methodology could be used on an individual company basis. However, the procedure in determining the Activity Data needs to be more clearly defined.

Nitric Acid Production

N_2O

State-wide Methodology: *Nitrous oxide emissions from nitric acid production were estimated using the following equation taken from the EIIP guidance (EIIP 1999):*

$$N_2O \text{ Emissions} = \text{Nitric Acid Production} \times EF$$

Where:
EF = N_2O Emission Factor (Default = 0.008 tons N2O/ton Nitric Acid Produced)

Data Source: The N_2O Emissions factor (EF) was based on the IPCC guideline default (IPCC 2000)

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the nitric acid production, which should be readily available.

Petroleum Systems

CH_4

State-wide Methodology: *Methane emissions from the petroleum system were estimated using methodology described in the EIIP guidance (EIIP 1999):*

$$CH_4 \text{ Emissions} = \text{Sum(Activity Data} \times EF) \text{ for Field Production} + \text{Sum(Activity Data} \times EF) \text{ for Transportation} + \text{Sum(Activity Data} \times EF) \text{ for Refining}$$

Where:
Activity Data = Statistics on oil production, amount of venting/flaring, quantity of oil tankered, and the quantity of oil refined.
EF = Emission factor (lbs. CH_4/MMBtu)

Data Sources: Activity data for field production includes: total oil production (CDC 2001) and the total vented and flared emissions (EIA 2001). Transportation activity data was obtained from the California Energy Commission, 1995 Fuels Report (Commission 1995). The total oil refined in California was obtained from the Commission, Monthly California Refining Industry Operating Report (Commission 1997-2000, Commission 2001)

Applicability: The fundamental concept behind the methodology could be used on an individual company basis. However, the procedure in determining the Activity Data needs to be more clearly defined.

Rice Cultivation

CH_4

State-wide Methodology: *Methane emissions from rice cultivation are estimated using the method outlined in the IPCC guidelines:*

CH_4 Emissions = Harvested rice area (hectares) x specific seasonal emission factor (kg CH_4/ha-season)

Where:
California's specific seasonal emission factor is 122 kg CH_4/ha-season.

Data Source: The California-specific seasonal emission factor was derived from published results of field measurements of CH_4 emissions from California rice fields (Cicerone et al. 1992, Bossio et al. 1999, Fitzgerald et al. 2000, and Redeker et al. 2000)

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the harvested rice area, which should be readily available.

Semiconductor Manufacturing

HFC-23, CF_4, C_2F_6, and SF_6

State-wide Methodology: The EIIP guidelines did not provide a method for estimating emissions from this source, therefore state-level estimates were taken as a percentage of the national emissions:

California semiconductor manufacturing emissions = U.S. semiconductor manufacturing emissions x (California population / National population)

Data Source: The primary data source used was the US Inventory (EPA 2001) which gave national emissions estimates.

Applicability: Methodology used to estimate California state emissions is not applicable on an individual company basis. This methodology uses the population of an entity to determine its emissions. This is not applicable since emissions depend on many attributes of the entity including the type and size of operating equipment and not based solely on the number of people employed. For example, a company might not operate any facilities that have semiconductor manufacturing emissions, but this methodology would incorrectly report emissions. Therefore, a new methodology must be developed.

Soda Ash Production and Consumption

CO_2

State-wide Methodology: *Estimates of CO_2 emissions from soda ash consumption were based on the following equation presented in the EIIP guidance (EIIP 1999):*

$$CO_2 \text{ Emissions} = \text{Soda Ash Consumption} \times EF$$

Where:
$EF = CO_2$ Emission Factor (0.415 tons CO_2/tons soda ash)

Data Source: National soda ash consumption data were obtained from U.S. Geological Surveys, Mineral Yearbooks: Soda Ash Annual Report, (USGS 1994 - 2000). National and California payroll data for the glass and soap manufacturing industries were obtained from U.S. Census Bureau, Annual Survey of Manufacturers (U.S. CB 1996). The soda ash consumption emission factor (EF) was taken from the EIIP guidelines (EIIP 1999).

Applicability: Methodology could be successfully used on an individual company basis since the only on-site measurement that needs to be made is the mass of soda ash consumed, which should be readily available.

Substitution of Ozone-Depleting Substances

ODS (Ozone-Depleting Substances)

State-wide Methodology: State totals were obtained based on a percentage of the national total:

$$\text{California ODS emissions} = \text{U.S. ODS substitute emissions} \times (\text{California population} / \text{National population})$$

Data Source: There was one primary data source used to develop estimates of Ozone-Depleting Substances (ODS) substitute emissions. National emission estimates of ODS substitutes were obtained from the US Inventory (EPA 2001).

Applicability: Methodology used to estimate California state emissions is not applicable on an individual company basis. This methodology uses the population of an entity to determine its ODS emissions. This methodology is not applicable since emissions depend on many attributes of the company including the type and size of operating equipment and not based solely on the number of people employed. For example, a company might not operate any facilities that emit ODS, but this methodology would incorrectly report emissions. Therefore, a new methodology must be developed.

Appendix C Industry-Specific GHG Emissions

Most GHG emissions occur as the result of the combustion activities described in Section 3.1. In addition to these sources, specific emission sources are associated with a wide variety of industrial processes. The California Climate Action Registry will be developing industry-specific guidance for reporting such GHG emissions. In this section, some of the common approaches used for estimating industrial GHG emissions are listed or sources of guidance on industrial emissions are presented. This material is meant to serve as examples of type of information that may be incorporated in future industry-specific protocols.

C.1 Cement Production

Approach

This cement-based GHG emission estimation methodology, derived from the U.S. EPA's *ClimateWise* program (EPA, 1999a), was taken from the GHG Protocol Initiative's "Calculating CO_2 process emissions from Cement Production (Cement-based Methodology)" (WRI, 2001). Of the different methodologies available, representatives from the Portland Cement Association (www.portcement.org) indicated that this is the prevalent procedure and that it is used successfully throughout the industry.

This procedure outlines the approach that an individual company should take in order to estimate CO_2 emission from cement production. This approach requires the following data:

- Cement production
- Clinker content of the cement
- Raw material content of the clinker

Step 1:Cement Production

Cement production is total amount of cement produced (tonnes) in a given time.

Table C.1 Cement Production

	Parameter	**Mass (tonnes)**
A	Cement Production	

Step 2: Production Data

Clinker to cement ratio is the clinker content of the cement (%). Raw material ratio is the tonnes of raw material used in a tonne of clinker (tonnes of raw material/tonne of clinker). $CaCO_3$ equivalent is the lime content of the raw materials (%).

Table C.2 Production Data

	Parameter	Value
B	Clinker to cement ratio (%)	
C	Raw material ratio	
D	$CaCO_3$ equivalent (%)	

Step 3: Chemical Data

$CO_2/CaCO_3$ stoichiometric ratio is the atomic weight of CO_2 divides by the atomic weight of $CaCO_3$

Table C.3 Chemical Data

	Parameter	Value
E	$CO_2/CaCO_3$ stoichiometric ratio	

Step 4: Default Data

Table C.4 Default Values[1]

Parameter	Default Value
Clinker to Cement Ratio (%) – 100% Portland output	95%
Clinker to Cement Ratio (%) – blended and/or masonry cement	75%
Tonne of Raw Material per Tonne of Clinker	1.54-1.60
CaCO3 Equivalent to Raw Material Ratio (%)	78%-80%
$CO_2/CaCO_3$ stoichiometric ratio[2]	0.44

[1]Default values were taken from GHG Protocol and EPA's ClimateWise Database (EPA, 1999a).
[2]Constant value

Step 5: Calculate Emissions

CO_2 Emissions = **A** x **B** x **C** x **D** x **E**

Discussion

This cement-based approach should only be used if the facility is confident in its data regarding the clinker content of the cement and its use of other raw materials. This approach does not consider performance ratios associated with variations in the production process such as blended cements, substitution of limestone by other Ca containing raw materials, or substitution of clinker by mineral products. Default values are given for reference but, when possible, actual field data should be used. The calculation worksheets are available at http://www.ghgprotocol.org.

C.2 Coal Mining

Approach

This approach was taken from "U.S. Methane Emissions 1990 – 2020: Inventories, Projections, and Opportunities for Reductions" (EPA, 1999b).

This procedure outlines the approach that an individual company should take in order to estimate CH_4 emission from coal mining. The approach only considers emissions from Surface Mines and from Post-Mining Operations. Data as far back ass 1990 indicates that there are no active underground coal mines in California. The procedure requires the following data:

- Coal production
- Average methane in-situ content of surface-mines coals

Step 1: Coal Production

Table C.5 Coal Production

	Parameter	Mass (tonnes)
A	Surface Coal Production	

Step 2: In-Situ Methane Content

Table C.6 In-situ Methane

	Parameter	Value (m^3/tonne)
B	Average Methane In-Situ Content of Surface Mines Coals	

Step 3: Emission Factors

Table C.7 Emission Factors

	Parameter	Value (m^3/tonne)	Default*
C	Surface Mining Emission Factor	**= B** x 2	0.2
D	Post-Mining Emission Factor	**= B** x 0.325	0.0325
* Using site-specific data gives more accurate results. The default values should only be used if site-specific data is unavailable.			

Step 4: Emissions

CH_4 Emissions from Coal Mining = **A** x (**C**+**D**)

Discussion

Default values are given only if no site-specific data is available, but every attempt should be made to obtain site-specific data.

C.3 Electric Utilities SF_6 Emissions

Approach

This approach was taken from the “SF_6 Emissions Reduction Partnership for Electric Power Systems” published by the United States Environmental Protection Agency as a Memorandum of Understanding for the voluntary agreement between the USEPA and a volunteering party. Of all the approaches available, the recommended approach was chosen because it has been used and accepted by electric utilities in the industry.

This procedure outlines the approach that an individual company should take in order to estimate SF_6 emission from electric utilities. The procedure requires the following data:

- SF_6 gas in inventory at the beginning of the reporting year
- SF_6 gas in inventory at the end of the reporting year
- SF_6 gas additions to inventory (i.e., purchases)
- SF_6 gas subtractions from inventory (i.e., sales or returns)
- Changes in nameplate capacity

Step 1: Calculate Base Inventory

Table C.8 Base Inventory

	Inventory	Amount (kgs)
A	Beginning of year	
B	End of year	

Step 2: Calculate Changes to Inventory

Table C.9 Inventory Changes

Additions to Inventory		
		Amount (kgs)
1	Purchases of SF_6 (including SF_6 provided by equipment manufacturers with or inside new equipment)	
2	SF_6 returned to the site after off-site recycling	
C	**Total Additions (add items 1-2)**	
Subtractions from Inventory		
		Amount (kgs)
3	Sales of SF_6 (to other entities, including the gas left in retired breakers)	
4	Returns of SF_6 to supplier	
5	SF_6 taken from storage and/or equipment and disposed of	
6	SF_6 taken from storage and/or equipment and send off-site for recycling	

D	**Total Subtractions (add items 3-6)**	
Change to Nameplate Capacity		
		Amount (kgs)
7	Total nameplate capacity of new equipment	
8	Total nameplate capacity of retiring equipment	
E	**Change to nameplate capacity (subtract item 8 from 7)**	

Step 3: Calculate Total Annual Emissions

Total Annual Emissions = **A – B** + **C – D – E**

Discussion

Gas in inventory refers to SF_6 gas contained in cylinders, gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. Gas additions and gas subtractions refer to SF_6 gas placed in or removed from the stored inventory, respectively. Gas additions also include SF_6 provided by equipment manufacturers with or inside new equipment.

C.4 Lime Production

Approach

This approach was taken from the GHG Protocol Initiative's "Calculating CO_2 Emissions from the Production of Lime" (WRI, 2001).

Step 1: Lime Production

Enter the total mass (tonnes) of each type of lime produced in the table below.

Table C.10 Lime Production Data

	Lime Type	Mass (tonnes)
A	High-Calcium Lime	
B	Hydraulic Lime	
C	Dolomitic Lime	

Step 2: Default Values

Table C.11 Default Values

Stoichiometric Ratio (CO_2/CaO)	
High-Calcium Lime	0.79
Hydraulic Lime	0.79
Dolomitic Lime	0.91
CaO or CaO-MgO Content (%)	
High-Calcium Lime	93%
Dolomitic Lime – Developed Countries	95%
Dolomitic Lime – Developing Countries	85%
Hydraulic Lime	75%

Step 3a: Calculating Emissions from High-Calcium and Hydraulic Lime

CO_2 Emissions = **A** x Stoichiometric Ratio of CO_2/CaO x CaO Content of Lime

Step 3b: Calculating Emissions from Hydraulic Lime

CO_2 Emissions = **B** x Stoichiometric Ratio of CO_2/CaO x CaO Content of Lime

Step 3c: Calculating Emissions from Dolomitic Lime

CO_2 Emissions = **C** x Stoichiometric Ratio of CO_2/CaO x CaO-MgO Content of Lime

Discussion

Default values are given as a reference and site-specific data should be used whenever possible. The calculation worksheets are available at http://www.ghgprotocol.org.

C.5 Nitric Acid Systems

Approach

This approach was taken from the GHG Protocol's "Calculating N_2O Emissions from the Production of Nitric Acid" (WRI, 2001).

The following need to be determined:

1. Quantity of nitric acid produced (tonnes)
2. N_2O emissions factor (kg of N_2O/tonnes of nitric acid produced)
3. N_2O destruction factor (fraction of emissions abated by reduction technologies)
4. Abatement system utilization factor (fraction of time the abatement system was in use)

Step 1: Quantity of Nitric Acid Produced

Table C.12 Nitric Acid Production

	Parameter	Mass (tonnes)
A	Quantity of Nitric Acid Produced (tonnes)	

Step 2: N_2O Emissions Factor

N_2O emissions factor is the mass (in kgs) of N_2O divided by the mass (in tonnes) of nitric acid produced.

Table C.13 N_20 Emissions Factor

	Parameter	Value
B	N_2O emissions factor	

Step 3: N_2O Destruction Factor

N_2O destruction factor is the fraction of emissions abated by reduction technologies.

Table C.14 N_2O Destruction Factor

	Parameter	Value
C	N_2O destruction factor	

Step 4: Abatement Utilization Factor

Abatement system utilization factor is the fraction of time the abatement system was in use.

Table C.15 Abatement Utilization Factor

	Parameter	Value
D	Abatement system utilization factor	

Step 5: Default Emission Factors

Table C.16 N_2O Default Emission Factors

Parameter	Emission Factor (kg N_2O/ tonne HNO_3)
Atmospheric pressure plant	4-5
Medium pressure plant (<6 bar)	6-8
High pressure plant (>7 bar)	9

Table C.16 N_2O Default Abatement Factors

Parameter	Emission Factor (kg N_2O/ tonne HNO_3)
Non-selective catalytic destruction	0.8 – 0.9
Selective catalytic destruction	0
1. Under certain conditions, selective catalytic reduction can even result in an increase of N2O emissions.	

Step 6: Calculate N_2O Emissions

N_2O Emissions = **A** x **B** x (1 – (**C** x **D**))

Discussion

N_2O emissions from the production of nitric acid depend on the quantity of nitric acid produced, plant design, burner conditions and on the amount of N_2O destroyed in any subsequent abatement process. In the United States, many plants use non-selective catalytic reduction to reduce NO_X emissions and this technology also results in reduced N_2O emissions. The calculation worksheets are available at http://www.ghgprotocol.org.

C.6 Petroleum and Natural Gas Systems

Petroleum and natural gas systems have a wide range of GHG emissions sources. Because of the similarity of the operations, particularly in oil and gas production, they are often considered together. Specific emissions estimation approaches that apply to the oil and gas industry are beyond the scope of this general protocol. Participants in the oil and gas industry may consult the following sources of information to estimate their emissions:

- Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry (API, 2001)

- GHGCalc™, a computer program developed by the Gas Research Institute for estimating GHG emissions from gas industry operations (GRI, 1999)

- Methods for Estimating Methane Emissions from Natural Gas and Oil Systems (EPA, 1999c)

C.7 Semiconductor Manufacture

Approach

This approach was taken from the GHG Protocol Initiative's "Calculating PFC Emissions from the Production of Semiconductor Wafers" (WRI, 2001). Of the different approaches available, the recommended approach is the most straightforward.

Step 1: Mass Purchased

Enter total amount of each material purchased for current reporting year:

Table C.17 Mass Purchased

Gas_I	PFCi (kgs)
C_2F_6	
CF_4	
CHF_3	
SF_6	
NF_3	
C_3F_8	
C_4F_8	

Step #2 – Fraction Abated

Enter the overall fraction (between 0 and 1) for each gas that is fed into the abatement tools.

Table C.18 Fraction Abated

Gas_I	V_a
C_2F_6	
CF_4	
CHF_3	
SF_6	
NF_3	
C_3F_8	
C_4F_8	

Step 3: Default Values

Table C.19 Default Values

Process Chemical	C_i	$a_{i,j}$	$EF_i = 1 - C_i$
C_2F_6	0.30	90.0	0.70
CF_4	0.20	90.0	0.80
CHF_3	0.70	90.0	0.30
SF_6	0.50	90.0	0.50
NF_3	0.80	90.0	0.20
C_3F_8	0.60	90.0	0.40
C_4F_8	0.70	90.0	0.30

Table C.20 Byproduct EF

Byproduct EF	B_i
$C_2F_6 \rightarrow CF_4$	0.10
$C_3F_8 \rightarrow CF_4$	0.20

Step 4: Perform Calculations

Emissions for PFC_i = $PFCi*(1-h)[EF_i*(1-A_i) + B_i*(1-A_{CF4})]$

Where:
From Step #1

PFC_i = purchases of gas_i

From Step #2

V_a = fraction of gas_i that is fed into the abatement tools
$a_{i,j}$ = average destruction efficiency of abatement $tool_j$ for gas_I
A_i = fraction of PFC_i destroyed by abatement = $a_{i,j}*V_a$
a_{CF4} = average destruction efficiency of abatement $tool_j$ for CF_4
A_{CF4} = fraction of PFC_i converted to CF_4 and destroyed by abatement = $a_{CF4}*V_a$

From Step #3

h = fraction of gas_i remaining in container (heel)
C_i = average utilization factor of gas_i (average for all etch and CVD processes)
EF_i = average emission factor of gas_i (average for all etch and CVD processes) = 1 - Ci
B_i = mass of CF_4 created per unit mass of PFC_i transformed

Discussion

These guidelines have been prepared by World Semiconductor Council (WSC) and are intended to facilitate the calculation of direct PFC emissions from the production of semiconductor wafers. These calculations are derived from Tier 2 standards as reported in the "Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories" (IPCC, 2000). For a complete analysis, please visit http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm. The calculation worksheets are available at http://www.ghgprotocol.org.

C.8 Soda Ash Production and Consumption

Recommended Approach

This approach was taken from the EIIP's "Methods for Estimating Non-Energy Greenhouse Gas Emissions From Industrial Processes" (EIIP, 1999).

Step 1: Obtain Required Data

Table C.21 Required Data

	Parameter	Mass (tonnes)
1	Amount of Soda Ash Consumed	

Step 2: Estimate CO_2 Emissions from Soda Ash Consumption

CO_2 Emissions (tonnes) = Amount of Soda Ash Consumed (tonnes) x 0.415 (tonnes CO_2/tonnes Soda Ash)

Discussion

According to the EIIP's "Methods for Estimating Non-Energy Greenhouse Gas Emissions From Industrial Processes" (EIIP, 1999), all states consume soda ash, but only Wyoming and California produce it and each in different ways. Although CO_2 is generated as a by-product in the typical Californian production, the CO_2 is recovered and recycled for use in carbonation stage and is not released. Thus, this process does not result in CO_2 emissions.

Also according to the EIIP's "Methods for Estimating Non-Energy Greenhouse Gas Emissions From Industrial Processes" (EIIP, 1999), glass manufacture represents about 49 percent of domestic soda ash consumption, with smaller amounts used for chemical manufacture, soap and detergents, flue gas desulfurization, and other miscellaneous uses. In each of these applications, a mole of carbon is released for every mole of soda ash used. Thus, approximately 0.113 tonnes of carbon or 0.415 tons of CO_2 are released for every ton of soda ash consumed.